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October 3, 2024

Ms. Lisa Felice *Via E-File*
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

RE: MPSC Case No. U-21534

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Initial Brief of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan; and
- Proof of Service.

Please note that there is a Confidential Version of the Initial Brief, which will be filed under seal and served to only those with an NDC on file in this case.

Sincerely,

Digitally signed by Tracy Jane Andrews
DN: cn=Tracy Jane Andrews, o=Troposphere Legal, PLC, email=tjandrews@tropospherelegal.com, c=US
Date: 2024.10.03 18:13:51 -04'00'

Tracy Jane Andrews
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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.	Case No. U-21534

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

October 3, 2024

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I. INTRODUCTION

In this case, DTE Electric Company (DTE) seeks to increase annual base revenues by $456.4 million for a projected test year of calendar year 2025.[1] This is a proposed total 8.2% increase but for residential customers, it would be a 9.6% increase, while only a 4.3% increase for primary customers.[2] For residential customer bills, this increase amounts to about a monthly $11.12 to $12.97 increase (summer rate) for customers whose monthly consumption is 600 to 700 kWh.[3] At the same time, the Company requests a higher authorized return on equity, from 9.9% approved in U-21297 to 10.50%.[4]

The Company proposes to continue massive "strategic" capital spending on the distribution system - $827.280 million in 2025, with IRM spending up to $1.7 billion through 2027.[5] DTE residential customers already suffer poor distribution reliability (outages) and high rates.[6] Distribution investments are allocated relatively higher to the residential class. DTE has been aggressivelymassively increasing distribution capital spending over the last decade supported largely by promises of reliability benefits while its reliability remains consistently worse than its peers.[7] The Company's proposals to increase spending and returns for its investors while barely moving the needle on reliability are unacceptable for residential ratepayers. The Commission must

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[1] DTE Electric, March 28, 2024, Application.

[2] DTE Application, Attachment 4.

[3] DTE Application, Attachment 3.

[4] Direct Testimony of Bente Villadsen, 6 TR 2446.

[5] Ex A-12 Sch B5.4 line 22.

[6] Ex A-23 Sch M8 (2023 Distribution Grid Plan), pp. 39-41 of 274 (reliability); Ex MEC-2, p. 4 (residential rates).

[7] *Id;* Direct Testimony of Paul Alvarez, 6 TR 3924 (DTE distribution capital spending increased from under $500 million in 2015 to $1.6 billion in 2024, and DTE plans to increase to $2.2 billion in 2028).

scrutinize the Company's proposals and ensure they are supported with credible evidence, not just promises.

DTE's latest request for increased revenue and return on equity (ROE) should be considered in the context of patterns concerning DTE's prior requests for increases in revenue and ROE, and the effect that the approved rates had on residential customers. Between 2015 and 2023, DTE requested and received approval for increases in revenue and ROE from the Commission seven times.[8] These cases illustrate that DTE consistently requests very high increases in revenue and ROE, and the Commission consistently approves high increases in revenue and ROE that increase monthly costs for residential DTE customers.

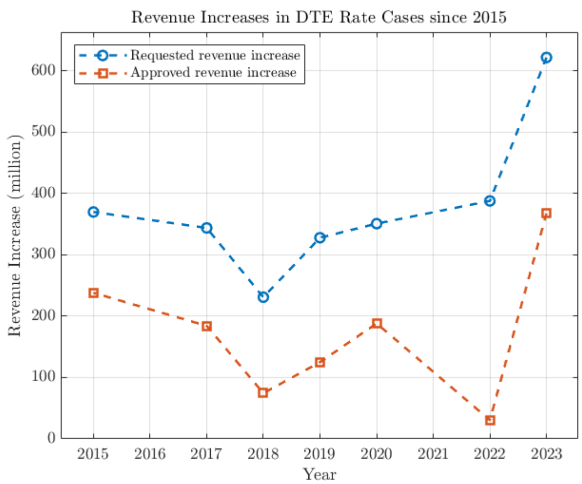
Since 2015, DTE has consistently requested a revenue increase that is significantly greater than what the Commission ultimately approved, as shown below in the graph on the left.[9] At the same time, DTE routinely requests ROE increases in each rate case filing. The Commission has been unwilling to approve the requested ROE increases, though ROE reductions across these cases have been quite gradual; the total ROE movement from 2015 to present moved a mere 0.4 basis points, as seen in the graph on the right:[10]

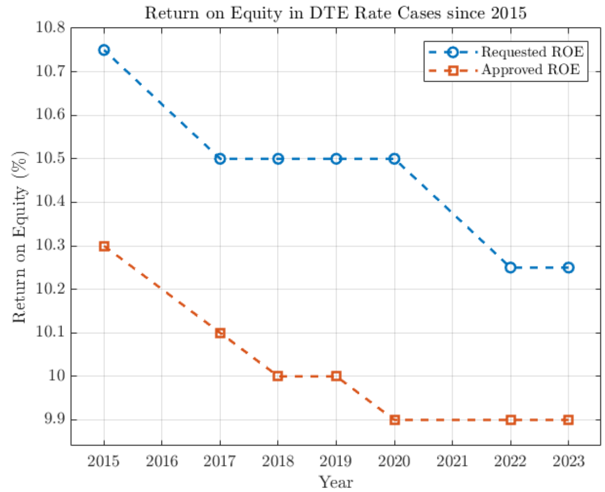
[8] MNSC refers here to the following Commission orders:

- Case No. U-21297, December 1, 2023, Order;
- Case No. U-20836, November 18, 2022, Order;
- Case No. U-20561, May 8, 2020, Order;
- Case No. U-20162, May 2, 2019, Order;
- Case No. U-18255, April 18, 2018, Order;
- Case No. U-18014, January 31, 2017, Order;
- Case No. U-17767, December 11, 2015, Order.

[9] Approved and requested revenue increases from the final order in each of the cases cited above.

[10] Approved and requested ROE from the final order in each of the cases cited in footnote 8 above.





These consistent revenue increases combined with high ROEs result in increased costs for residential customers. In 2019, 2020, and 2023, a monthly bill for an average residential customer (defined as using 500 kilowatt hours of electricity per month) increased from between $3.93-$6.51 per month.[11]

If the Commission were in this case to accept DTE's requested ROE and revenue increase without changes, DTE would collect about $1.31 billion from customers for a return on its rate base, based on an overall rate of return of 5.92% and a total jurisdictional electric rate base of $22.1 billion.[12] Reducing the ROE to 9.30 percent, which witness Bandyk demonstrated to be a market-based cost of equity, would result in savings to customers of about $104 million on an annualized basis even without changing the rate base.[13]

Just like in previous cases, residential customers, especially those with low incomes, will bear the brunt of any increase that the Commission ultimately authorizes. NRDC-MEC witness Roger Colton presented an affordability analysis that found that in the zip codes comprising the

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[11] Average residential customer bills in the final order in each of cases cited in footnote 8 above.

[12] Direct Testimony of CUB-MEC witness Mathew Bandyk, 6 TR 3747-48.

[13] *Id*.

DTE service territory, there are 819,913 households living with annual income at or below $40,000, of which 17.8% have income less than $10,000 and 14.4% have income between $10,000 and $14,999.[14] If the Commission accepts DTE's proposed rates, these customer segments face electricity burdens of 31% and 12.4%, respectively.[15] These customers already faced substantial unaffordability; DTE's requests threaten to exacerbate that unaffordability.

The patterns illustrated by DTE's past rate cases should inform the Commission's decisions on DTE's revenue increase, ROE, and other requests in this case. The Commission may consider a broad range of factors and interests when setting rates. The Commission must set "just and reasonable"[16] rates that balance both "investor and the consumer interests."[17] This balancing should include consideration of affordability as a critical consumer interest. As Mr. Colton testified:

> Indeed, of the customer issues that are important drivers of the just and reasonable ROE determination, one of the most significant is the concern about affordability. If a sizable portion of customers cannot afford to pay the rates imposed by the Commission, the Commission can hardly be said to have approved just and reasonable rates.[18]

The Commission has already acknowledged that affordability is a legitimate consumer interest and that rates should not "place an unnecessary burden on ratepayers."[19] The pattern established in prior DTE rate cases is that DTE consistently requests unreasonable revenue and ROE increases, and the Commission consistently approves revenues and an ROE that increases

[14] Direct Testimony of NRDC-MEC witness Roger Colton, 6 TR 3874-75.

[15] *Id*. at 3873.

[16] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923).

[17] *Fed. Power Comm. v Hope Natural Gas Co.*, 320 US 591, 603; 64 S Ct 281, 288; 88 L Ed 333 (1944).

[18] 6 TR 3879-80.

[19] Case No. U-15244, December 23, 2008, Order, pp. 12. ("[T]he rate of return *should not be so high as to place an unnecessary burden on ratepayers*, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise") (emphasis added).

costs for the average residential customer. Each approved rate increase means DTE electric services become less affordable for more residential customers, and its rates become less "just and reasonable" as a result.

In this initial brief, the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and the Citizens Utility Board of Michigan (MNSC) present our position on the following issues:

Distribution System Capital Spending: The Commission should disallow significant proposed strategic capital spending in the bridge and test years. In particular, MNSC supports disallowances in the Infrastructure Resilience and Hardening programs, Infrastructure Redesign and Modernization programs, and Technology and Automation programs, which total $131.213 million for 2024 bridge and $274.353 million for 2025 test year spending. The Company has not shown that numerous subprograms in these discretionary programs are reasonable and prudent.

Tree Trim Capitalization for Distribution Capital Projects: MNSC continues to oppose the Company's practice of capitalizing tree trim expense because it is contrary to the USOA and results in unnecessary cost increases for ratepayers.

EV Charging Forward: MNSC supports, with minor modifications, DTE's ongoing Charging Forward program and its proposed Transportation Electrification Plan because its proposals are consistent with guidance for utility-funded electric vehicle programs, broadly supported by stakeholders and parties, target barriers to EV adoption, and focus on addressing equity by prioritizing investments in low-income and disadvantaged communities. MNSC supports approval without endorsement of DTE's benefit-cost methodology, opposes added CIAC, recommends improvements to load profiling, and requests DTE prioritize NEVI applicants for on-route DCFC charging and public and school transit federal grant recipients.

Return on Equity: The Commission should reject the Company's request for approval to increase its ROE to 10.5% because it has not proven it is reasonable and fair. Instead, ample credible evidence supports an authorized ROE of 9.3%. In addition to the traditional analyses, the Commission may consider that DTE's rates are already so high as to be unaffordable for many customers, and its reliability performance is poor. The Commission has ample authority under existing precedent to consider these facts when determining where in the range of ROEs produced by the cost of equity models to approve DTE's ROE.

O&M Inflation Rates: MNSC supports a productivity adjustment to DTE's projected O&M inflation rate, or alternatively the inflation rate proposed by ABATE or the Attorney General.

Tree Trim Surge and Risk Model Audits: As DTE nears the end of its transition to get all circuits on the 5-year cycle under its Enhanced Tree Trim Program (ETTP), MNSC supports an independent audit of DTE right-of-ways to develop a baseline to be followed by periodic audits to ensure DTE does not fall behind on the 5-year cycle. And while MNSC generally supports the concept of variable trim cycles supported by modeling, MNSC requests an independent audit and evaluation of DTE trim planning and the model to evaluate its results and improve the model and outcomes for customers.

Outage Credit Recovery: MNSC oppose DTE's proposal for recovery of outage credits for a wide variety of causes and favor limiting recoverability to outages caused by the transmission operator or another utility, and on the condition that DTE seek recovery of costs from the responsible party.

Voluntary Separation Incentive Package (VSIP): MNSC oppose DTE's proposal to recover from ratepayers the projected O&M expense saved as a result of the Company's large-scale voluntary buy-out program.

Low Income (RIA and LIA) Programs: MNSC propose that DTE shift from a flat Low-Income Assistance (LIA) credit to a tiered system of credits that would meaningfully alleviate energy burdens for customers with low incomes. MNSC also propose other improvements to DTE's low-income programs, including streamlining eligibility documentation and modifying arrearage forgiveness credits. MNSC oppose Staff's position that the Commission should delay evaluation of proposed improvements to DTE's low-income programs.

Return on Tree Trim Regulatory Asset: MNSC opposes the Company's request for a return on its ETTP Surge Regulatory, given the Company's negligent failure to maintain vegetation management on the industry-standard 5-year cycle. In addition, MNSC opposes the Company's proposal to apply the long-term debt rate to this asset and – if a return is authorized – it should be maintained at the short-term debt rate.

Strategic Underground Pilots: MNSC oppose continued investment in the Company's strategic undergrounding pilots because they have been repeatedly shown to be exorbitantly expensive and highly cost-ineffective.

Construction in Aid of Construction: The Commission should direct DTE to maintain accurate and up-to-date CIAC rates based on construction costs with regular updates to its CIAC standards.

Future Cases – Cost of Service and Rate Design: To address inequities in cost allocation and better prepare rate design for growth in building electrification, the Commission should direct

DTE to file an analysis in its next rate case of the seasonality of distribution cost causation, and to evaluate potential residential sub-classes for multi-family homes and electric heating.

Investment Recovery Mechanism: MNSC oppose the Company's request to extend by two years and expand to $1.7 billion its distribution IRM.

II. RATE BASE

A. Projected Rate Base (Reserved)

B. Working Capital (Reserved)

C. Corp Staff & Facilities (Reserved)

D. Distribution Operations Capital

1. Base Capital Programs (Reserved)
2. Strategic Capital: The Commission should maintain recent historical distribution strategic capital spending levels and reject the Company's proposed spending increases as they are premature and unsupported.

DTE proposes to increase spending on Distribution Strategic Capital Programs by $113 million from historical year 2022 to test year 2025.[20] Six Strategic Capital Programs are also included the Company's proposal to extend and expand the IRM.[21] The Company supported its proposed Distribution Strategic Capital Programs investment plan both in the test year and IRM with testimony from witnesses Kryscynski, Elliott Andahazy, Hartwick, and Deol.

AG-MN witnesses Alvarez and Stephens opposed aspects of the Company's proposed Distribution Strategic Capital investment plan – both the foundations of the overall investment plan (particularly the 2023 DGP, GPM, and Reliability Model) and some of the programs directly.

[20] Ex A-12 Sch B5.4, p. 1 line 22.

[21] Ex A-33 Sch X1.

Mr. Alvarez testified about the Company's overall approach to its spending request and the case the Company provided in support.[22] Foundationally, he opposed the premise that the Company's increased capital spending will result in the promised reliability benefits. He noted the regulatory incentive for capital spending may influence the utility's preference for capital projects, as evidenced by the Company's spending plan through at least 2028. He further noted the lack of transparency about the rate impacts of the Company's planned capital spending increases, as well as the disconnect between the causes of poor reliability and the Company's spending plans. While DTE has increased distributions system capital spending since 2015, system performance has deteriorated for ratepayers and also relative to other investor-owned utilities. He cautioned that more capital spending is not necessarily the panacea to improve reliability and supported careful regulatory oversight of program cost-effectiveness. To that end, Mr. Alvarez recommended slowing capital spending increases until DTE provides necessary data to evaluate program effectiveness and cost-effectiveness. He raised particular concerns with regulatory governance challenges associated with the Company's proposal to extend and expand the IRM for the same Distribution Strategic Capital programs.[23]

At bottom, the Company's proposals to substantially increase spending in six programs in the test year and IRM are premature in this case. It would be premature to increase spending before the Company has demonstrated with reliable, verifiable historical data that each proposed investment in these Distribution Strategic Capital Programs is likely to produce the promised reliability benefits for ratepayers and that the ratepayer benefits are worth ratepayer costs. The Company did not provide such assurances in this proceeding. For example, for its "mature" 4.8kV

[22] Alvarez Direct, 6 TR 3924-37.

[23] Alvarez Direct, 6 TR 3947.

Hardening,[24] pole and pole-top replacement (PTMM), and conversions programs, Company plans would increase spending before proving benefits. The new Distribution Automation proposal to deploy Viper reclosers across the system with massive spending increases (from $5.5 million in 2022 to $150 million in 2025) is supported by assurances without demonstrations of benefits. For many programs, the Company's spending plan remains unsupported, untransparent, and incomplete. Requesting approval for massive spending is further premature because the Commission's audit of the DTE distribution system is not yet complete.[25] These spending increases precede any meaningful metrics to ensure accountability that high spending levels will produce identified benefits – the Commission docket evaluating distribution performance-based metrics and methods to provide incentives and disincentives (performance based ratemaking) is ongoing.[26] Spending increases for Distribution Strategic Capital Programs based on projected future benefits are premature before regulators and ratepayers have the assurances that PBR offers. The request to increase and extend spending in these programs beyond 2025 through the IRM is also premature because there has not yet been a full cycle to test the mechanics and efficacy of reconciliation.

This brief first discusses the foundational elements of the Company's proposed Distribution Strategic Capital Programs investment plan and then addresses the particular programs driving spending increases.

[24] Elliott Andahazy Rebuttal, 4 TR 1040.

[25] Case No. U-21305, Sept. 26, 2024, Order.

[26] Case No. U-21400, June 6, 2024, Order.

i. DTE's Global Prioritization Model is flawed and does not justify specific distribution strategic capital programs.[27]

DTE supports its distribution capital investment plan in part with testimony from Witness Kryscynski and the results of a run of the Global Prioritization Model (GPM).[28] While DTE first developed the GPM several years ago,[29] this is the first proceeding where it was produced and made available to intervenors and the Commission.[30] Mr. Kryscynski explained how the GPM works: in essence, it scores distribution capital programs and projects across 10 weighted "impact dimensions" then ranks each program/project relative to the other programs/projects being scored and ranked.[31] The main output of the GPM is a Top 50 list with scores.[32]

In the last rate case, the Commission noted intervenors' concerns about the GPM.[33] To the extent DTE relies on the GPM to support capital spending, the Commission noted DTE should "provide the intervenors and the Commission with a full understanding of how these projects were selected and why they were selected" to facilitate evaluation of whether they are reasonable and prudent.[34] While the Company produced a copy of the GPM in this case, DTE's reliance on the

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[27] MNSC believes the following is the record on this issue:

- Direct Testimony of DTE witness Allen J. Kryscynski, 4 TR 346-61; Rebuttal Testimony of Mr. Kryscynski, 4 TR 419-433; and Cross Examination of Mr. Kryscynski, 3 TR 535-596;
- Ex A-23 Sch M8, M1; Ex A-43 Sch HH4;
- Direct Testimony of AG, MEC & NRDC witness Paul Alvarez, 6 TR 3958-65;
- Ex MEC-33, 36, 37, 71;
- Direct Testimony of CEO witness Curt Volkman, 6 TR 3242-45;
- Rebuttal Testimony of DAAO witness Jackson Koeppel, 6 TR 4440-46.

[28] Kryscynski Direct, 4 TR 346-361; Ex A-23 Sch M14.

[29] Kryscynski Cross, 3 TR 471 (estimating it was developed "five to eight years ago").

[30] Ex A-43 Sch HH4 (read-only copy of GPM); Ex MEC-71 (working version of GPM). See Case No. U-21297, December 1, 2023, Order, pp. 71-72 (noting the GPM "remains a black box").

[31] Kryscynski Direct, 3 TR 346-57; Kryscynski Cross, 3 TR 471-5.

[32] Kryscynski Direct, 3 TR 357; Ex A-23 Sch M14.

[33] Case No. U-21297, December 1, 2023, Order, pp. 64-73; PFD, 188-90.

[34] Case No. U-21297, December 1, 2023, Order, p. 72.

GPM – and in particular, on a program/project's ranking on the Top 50 list – remains fundamentally insufficient to support the reasonableness and prudence of planned capital investments. AG-MN witness Alvarez addressed GPM shortcomings[35] and additional flaws are evident from the model runs themselves.

The key problems with the GPM are as follows, discussed further below:

1. It is subjective and easily manipulated to achieve desired outcomes.
2. It ranks whole programs against discrete projects.
3. It is not a cost-benefit analysis.
4. It appears to justify rather than guide DTE capital investment decision-making.

The GPM is subjective in several ways. It allows the modeler to choose whether to include or exclude programs or projects in rankings, which means DTE selects which programs to rank.[36] One result is that the Top 50 programs/projects list varies depending on why it is being presented. DTE presented a Top 50 list to support planned capital investments in U-21297 – a model run from early 2023.[37] DTE presented a different Top 50 list to support planned capital investments in the 2023 DGP, from the summer of 2023.[38] Then DTE presented another different Top 50 list to support planned capital investments in this case.[39] Over the course of about 12 months, ADMS: DMS/OMS went from top rank[40] to absent[41] to top rank.[42] As seen in the working GPM model,

[35] Alvarez Direct, 6 TR 3959-62.

[36] Kryscynski Cross, 3 TR 491-3.

[37] Ex MEC-36; Kryscynski Cross, 3 TR 488-9 (ran GPM Top 50 for U-21297 in early 2023).

[38] Ex A-23, p. 259 of 274, Appendix F; Kryscynski Cross, 3 TR 486-7 (ran GPM Top 50 for 2023 DTP in summer 2023).

[39] Kryscynski Direct, 3 TR 357; Kryscynski Cross, 3 TR 486.

[40] Ex MEC-36 (U-21297 run in early 2023).

[41] Ex A-23 Sch M8, Appendix F (2023 DGP run in mid-2023); Kryscynski Cross, 489-91.

[42] Ex A-23 Sch M14 (U-21534 run in early 2024).

DTE evaluated about 189 programs/projects but only ranked 138 programs/projects.[43] Some program/projects that were included in its capital investment plan are in the GPM but neither scored nor ranked, like Grid Automation Telecommunications; and some are scored but not ranked, like Distribution Sensing and Monitoring (including Line Sensors).[44] The model can and is manipulated to decide which programs/projects to rank for particular purposes.

Subjectivity is also evident in the fact that program/project scores in each "impact dimension" are not objective data (historical experience, research, pilot results) but are subjective GPM inputs from DTE's modeling, engineering, and other teams.[45] The GPM scores programs/projects based on projected future benefits they will produce, and those benefits are based on what DTE personnel believe benefits will be (*e.g.*, wire down or SAIDI reductions).[46] Scoring is also influenced by manually entered risk probability and the relative size of the benefit from DTE subject matter experts (SMEs), adding more subjectivity to scoring.[47] Projected benefits are not a result of the GPM but an input into the GPM from DTE personnel.[48] In scoring, SMEs also assess the probability that a project will achieve the projected benefits, another layer of subjectivity.[49] There is no visibility or transparency around why project scores change in the same program year to year. For example, ADMS: DMS/OMS scored 1,353 in Total Safety in the U-

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[43] Ex MEC-71, GPM Results Tab, comparing columns B-AB (ranked programs/projects) to columns AI-AZ (all programs/projects); Kryscynski Cross, 3 TR 497-9.

[44] Ex MEC-71, GPM Results Tab, rows 14 and 24, columns AI-AZ; Ex A-14 Sch B5.4 p 17 lines 6, 7; Kryscynski Cross, 3 TR 499-502.

[45] Alvarez Direct, 6 TR 3960; Kryscynski Cross, 3 TR 513-7, 528-9.

[46] Kryscynski Cross, 3 TR 513-4.

[47] *Id* at 515-6.

[48] *Id* at 528-9; Ex MEC-71, Program-Project Benefits Tab.

[49] Kryscynski Cross, 3 TR 515-6.

21297 GPM run but scored 0 in Reduce Electrical Hazards (formerly Safety[50]) in the U-21534 run.[51]

There is also subjectivity in weighting – reliability scores are double "regulatory compliance" scores and quadruple cost-avoidance scores.[52] Weighting compounds scoring subjectivity. Even more subjectivity comes into the GPM based on the way DTE defines the scores, which may increase program/project score. Consider the "Regulatory Compliance" impact dimension, for example.[53] The PTMM program received a perfect score (100) in Regulatory Compliance because it meets the Staff's 2009 guidance to inspect poles every 10-12 years,[54] though only 3-4% of PTMM spending is on inspections (poles and pole tops).[55] Preemptive pole and pole top equipment *replacements* drive PTMM spending, but *inspections* drive it's perfect Regulatory Compliance score. And because Regulatory Compliance is weighted double, PTMM received 200 points due entirely to the itty-bitty inspections component.

Relatedly, the model can be manipulated by changing program/project costs. The model scores most impact dimensions using benefit-cost ratios that score programs/projects in unit benefits (*e.g.*, wire-down reductions or capital avoided) per dollar invested.[56] By reducing program/project costs, unit benefits per dollar increases. This manipulation may partly explain why PTMM rose from its middling rank No. 17 in U-21297 to No. 2 in U-21534: the program cost

[50] Kryscynski Direct, 3 TR 350 ("The 'Reduce electric hazards' dimension was previously named 'Safety'").

[51] Ex MEC-36, Ex A-12 Sch M14.

[52] Alvarez Direct, 6 TR 3960.

[53] Kryscynski Direct, 3 TR 351.

[54] Elliott Andahazy Direct, 4 TR 946.

[55] Kryscynski Direct, 3 TR 359; Kryscynski Cross, 3 TR 526-7; Ex MEC-71, Regulatory Compliance Tab; Ex A-12 Sch B5.4.8 lines 9, 13 (202: 3.6%; 2023: 0.3%; 2024: 4.3%; 2025: 3.1%).

[56] Kryscynski Direct, 3 TR 347; Kryscynski Cross, 3 TR 497.

went from \$1.6 billion in the U-21297 GPM run to \$715 million in the U-21534 GPM run.[57] All else being equal, this doubles benefits per dollar invested in PTMM. Like PTMM, Frequent Outage (CEMI) rose in rank from No. 23 in U-21297 to No. 3 in U-21534 – potentially due to the reduced investment. Program/project capital investments in the latest GPM run differ substantially from U-21297 – here are a few examples:

	U-21297 GPM Run Capital Investment[58]	**U-21534 GPM Run Capital Investment**[59]
PTMM	\$1,651,425,268	\$715,450,000
Frequent Outage (CEMI)	\$222,877,157	\$48,049,745
4.8kV Hardening	\$80,000,000	\$259,000,000
URD Replacement Program	\$105,000,000	\$72,041,398
Cable Replacement Program	\$140,171,395	\$91,501,597
Breaker Replacement Program	\$90,973,388	\$70,799,000
4.8kV CC: Almont Relief and Circuit Conversion (Midas)	\$3,565,012	\$30,730,922
CODI: Charlotte Network Upgrade	\$30,212,148	\$76,879,246
4.8kV CC: Buckler Circuit Conversion	\$5,512,442	\$20,723,990
4.8kV CC: Barber Substation and Circuit Conversion	\$72,268,116	\$44,056,537
4.8 kV CC: ISO Conversion Program	\$217,000,000	\$25,350,000
Subtransmission Redesign & Rebuild: Boyne	\$7,036,846	\$28,620,273

The manual capital investment input into the GPM adds subjectivity to the output for *programs* (PTMM, CEMI). But *project* costs also vary substantially year over year, notwithstanding the testimony that "entire project costs" are used in when scoring, apart from "adjust[ments] for known changes," to keep scoring "relatively consistent year over year."[60] The Midas project dropped from a rank of No. 10 in U-21297 to No. 95 in U-21534 – perhaps because the Major Event Reduction benefit per dollar invested dropped exponentially after the project cost

[57] Ex MEC-37 (U-21297 GPM run); Ex MEC-71, GPM Results Tab, line 11 col G.

[58] Ex MEC-37.

[59] Ex MEC-71, GPM Results Tab.

[60] Kryscynski Direct, 3 TR 355; Kryscynski Cross, 3 TR 484-5, 488.

increased 10-fold from one iteration to the next.[61] The Charlotte Network Upgrade dropped from No. 4 to No. 23 from the U-21297 run to the U-21534 run, also potentially reflecting its investment doubling. Program/project investment substantially influences scoring and is malleable.

Another flaw in the GPM is that it ranks programs against projects.[62] For example, the PTMM program ranked higher in the 2023 DGP and U-21534 model runs, and out-ranks any substation rebuild or conversion program. In effect, this means any mile of PTMM outranks every substation project. Obviously, there are circuits where PTMM is cost-effective and others where it is not – benefits will vary substantially for different circuits. That a program achieves more or less unit benefits per dollar invested than a project provides no practically useful information about spending on the program – how much to spend, where to spend, over what timeframe to spend, and more.

The GPM also provides no information whether a program/project is cost-effective – whether its potential benefits to ratepayers exceed likely ratepayer costs.[63] The GPM ranks programs/projects relative to each other in terms of benefits per dollar. So it may identify that PTMM (at the programmatic level) costs less to avoid a customer-outage-minute than a different project, but says nothing about whether the benefits of PTMM (programmatically or – more importantly – at the circuit level) exceed costs.

DTE appears to employ the GPM to *justify* its strategic capital investment decisions, not to *guide* decision-making. As Mr. Kryscynski testified, "we run the GPM to support our investment decisions."[64] While he also asserted DTE uses the GPM "to pick the highest relative benefit

[61] DTE never produced earlier versions of the GPM, only the scores and other data in MEC-37, so it is not possible to evaluate the impact of capital investment changes year over year.

[62] Alvarez Direct, 6 TR 3961.

[63] *Id.*

[64] Kryscynski Cross, 3 TR 486.

projects that will have the greatest impact,"[65] that claim is dubious. Many projects on the GPM Top 50 list are multi-year projects started years ago – DTE is unlikely to abandon an ongoing substation conversion or rebuild project if its ranking drops. DTE's process to approve large projects (>$10 million) appears wholly independent of how a project ranks on the latest GPM list. Take the Midas project, discussed above, which dropped from No. 10 to No. 95 from U-21297 to U-21534.[66] DTE produced its corporate approval for the project appropriation in discovery, which indicates the $30.3 million project was approved in 2021 and work started in at least 2020.[67] There is no evidence DTE picked the project because it of its GPM ranking, and DTE is unlikely to abandon the project on the basis its relative ranking dropped.

Similarly for program (versus project) decision-making, DTE appears to decide whether to pursue programs, and the scope of program spending, independent of GPM results. For example, in U-21297, notwithstanding the fact that 4.8kV Hardening ranked No. 3 on the U-21297 GPM run, DTE decided to wind-down Hardening and requested approval for only $6.7 million for 4.8kV Hardening in Test Year 2024.[68] Then in U-21534, Hardening ranked No. 7 on the U-21534 GPM run (lower than U-21297), but DTE proposes now to invest $125 million in Test Year 2025.[69] Email exchanges among the key decision-makers involved in setting rate case and IRM spending discuss considerations like "pass[ing] the smell test" and what the auditors signaled about programs, without mention of GPM rankings.[70]

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[65] Kryscynski Direct, 3 TR 355.

[66] Ex MEC-36 (U-21297 GPM run Top 50); Ex MEC-71, GPM Results Tab, row 104 (U-21534 GPM run results). Notably, the project capital investment in the U-21297 run was $3,565,012,

[67] Ex MEC-20.

[68] Ex MEC-90, Case No. U-21297, Ex A-12 Sch B5.4, p 8, line 12.

[69] Ex A-12 Sch B5.4, p. 13, line 12.

[70]Ex MEC-26, pp. 18-19, 27-27.

In rebuttal, Company witness Kryscynski opposes the concerns raised about the GPM.[71] He takes issue with the questions Mr. Alvarez poses about the Company's Strategic Capital Spending – whether these projects are cost-effective for customers and the optimal extent and timing (speed) of program deployment – suggesting these are not relevant or applicable questions to ask.[72] While it's not clear these are questions DTE is asking as it plans strategic distribution capital programs, they are certainly relevant for interveners and regulators to ask before approving their addition into rate base.

Mr. Kryscynski disagrees that scoring is subjective, pointing out that some GPM inputs are objective and some provided by SMEs.[73] The rebuttal misses the mark. While historical system reliability performance or circuit level wire downs may be GPM inputs, the GPM scores programs and projects using projections by DTE personnel of future reductions in, for example wire downs, SAIDI and SAIFI, major event risk, load relief, capital spending, and more. And projected benefits are multiplied by the probability an event or risk happening, also developed by DTE personnel, and the relative size of the event, also developed by DTE personnel.[74] The GPM might have some objective "inputs" but the project/program *score* in the GPM is the result of multiple subjective assessments of the program/project benefits external to the GPM.[75]

Take wire down reductions, a key driver for the *Reduce Electric Hazards* impact dimension. The U-21534 GPM run gives Distribution Automation a Wire Down Safey score of 1,980,443 based on a Wire Down Reduction of 7,686 and a Wire Down Percent of 66%.[76] The

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[71] Kryscynski Rebuttal, 3 TR 419-33.

[72] Kryscynski Rebuttal, 3 TR 420.

[73] Kryscynski Rebuttal, 3 TR 423-6.

[74] Kryscynski Cross, 3 TR 513-7, 528-9.

[75] Ex MEC-33.

[76] Ex MEC-71, Reduce Electrical Hazards Tab, row 16 columns F, G.

Reduction (7,686.1) and total system Wire Downs (11,643) are both hard numbers provided by DTE engineering team and data scientists.[77] The GPM gives the Distribution Automation program a *Reduce Electric Hazards* score of 286 based on its assumption that Distribution Automation will reduce wire-downs by a particular number. The Distribution Automation score may be technically *tied to* historic wire-downs on circuits planned for future automation, but the wire down reduction is a projection not tied to any data documenting the benefits (wire down reductions) of automation on any DTE circuit. As discussed below, this program lacks any historic data to back up projected wire-down reductions. The reduction projections are subjective, so the *Reduce Electric Hazards* score is subjective. The same is true for the Distribution Automation *Reliability - SAIDI* and *Reliability – SAIFI* scores – the Avoided Customer Interruptions (CI for SAIFI) and Avoided Customer Minute Interruptions (CMI for SAIDI) numbers are hard-entered in the model;[78] the CI and CMI reductions are based on subjective projections from DTE staff and consultants about the future benefits from a new program lacking any historic data to support or evaluate the projections. The scoring is not only subjective, but also opaque – the GPM provides no way to assess where and when such reductions are projected to materialize nor to validate them. There is thus no way to hold DTE accountable for its wire down, SAIFI, and SAIDI reduction projections.

The same is true for PTMM across multiple impact dimensions. DTE has not assessed wire-down, customer-interruptions, or customer minutes interrupted reductions on circuits where DTE has applied its PTMM upgrades and replacements.[79] It is not clear DTE has attempted to calculate avoided O&M or capital costs on historic PTMM circuits. Even so, the GPM assumes

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[77] Ex MEC-71, Reduce Electrical Hazards Tab, row 23 Distribution Automation column X, row 5 column Z; Kryscynski Cross, 3 TR 513-6.

[78] Ex MEC-71, Program-Project Benefits Tab, row 16 (Distribution Automation), columns G, H.

[79] Elliott Andahazy Cross, 4 TR 1090-3; Exs MEC-40, 55.

PTMM will avoid 297,893,299 customer minutes interrupted in 5 years and avoid $17,530,223 in O&M costs and $47,396,530 in avoided reactive capital costs.[80] PTMM was given a wire down reduction score of 1,078.7, a hard number developed by DTE SMEs outside the GPM.[81] As discussed below, DTE has not yet evaluated whether and to what extent PTMM reduces wire downs; the benefits are a projection of assumed benefits based on subjective inputs in the GPM. While there are objective inputs into the GPM, it is undisputed that the GPM scores programs and projects based on subjective judgments projecting future benefits. To the extent the GPM incorporates program benefits from the Reliability Model,[82] that model relies on unproven – and unrealistic – benefits projections, as discussed in further below.

Witness Kryscynski disagrees that the GPM can be manipulated because inputs are based on historical data, scoring methods have been consistent over time, DTE has requested input from stakeholders, and the GPM is in evidence.[83] None of these assurances mitigate the concern that the results are subjective and can be manipulated. Multiple variables can be modified, from whether to rank a program/project at all, to program/project costs, to projected benefits in terms of future wire-down, outage, and cost reductions. No prior versions of the GPM are in evidence so there is no way to know if scoring methods have been consistent over time. One known variable – program/project costs – has been notably *in*consistent over time, as shown in the table above comparing U-21297 and U-21534 costs.

At the end of the day, each run of the GPM results in a ranked list of Strategic Capital programs and projects selected for inclusion in the list. The GPM does not provide a useful or

[80] Ex MEC-71, Program-Project Benefits Tab, row 15 columns H, L, N.

[81] Ex MEC-71, Reduce Electrical Hazard Tab, row U PTMM column X.

[82] Kryscynski Rebuttal, 3 TR 429.

[83] Kryscynski Rebuttal, 3 TR 430.

objective way for stakeholders or the Commission to assess whether a Strategic Capital program or project is cost-effective nor whether the Company's proposed level of spending is reasonable and prudent. The reasonableness and prudence of particular program spending proposals are discussed below following the discussion of the Reliability Model.

ii. DTE's Reliability Model is flawed and does not justify specific distribution strategic capital programs.[84]

DTE cites its newer Reliability Model to support its Tree Trimming, Distribution Automation, PTMM, Customer Excellence, 4.8kV Hardening, and 4.8kV Conversions programs and overall reliability benefits associated with them.[85] Mr. Kryscynski explained how the Reliability Model works.[86] In a nutshell, the model attempts to project All-Weather SAIDI and SAIFI with and without each of these six programs. A read-only and working version of the Reliability Model are in evidence.[87]

AG-MN witness Alvarez addressed some shortcomings in the Reliability Model[88] and others are self-evident in the Reliability Model. One key flaw in the Reliability Model undermines any credibility in its results: the assumed reliability benefits (outage reductions) of each of the six programs are unsupported, unverified, and unreasonable. A quick summary of how the model

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[84] MNSC believes the following is the record on this issue:

- Direct Testimony of DTE witness Allen J. Kryscynski, 3 TR 361-6; Rebuttal testimony of Mr. Kryscynski, 3 TR 433-43; and Cross Examination of Mr. Kryscynski, 3 TR 469-534;
- Ex A-23 Sch M8, M9, M10; Ex A-43 Schs HH5, HH6; Ex A-53 Sch RR2 (CEII);
- Rebuttal Testimony of DTE witness Rachel C. Steudle, 6 TR 3001-2;
- Direct Testimony of AG, MEC & NRDC witness Paul Alvarez, 6 TR 3965-71;
- Ex MEC-4, 5, 33, 34, 35, 38, 65, 67, 70, 72;
- Direct Testimony of CEO witness Curt Volkman, 6 TR 3245-8.

[85] Kryscynski Direct, 3 TR 361-366.

[86] Kryscynski Direct, 3 TR 362-5; Kryscynski Cross, 3 TR 536 (DTE developed the Reliability Model in 2023 for the 2023 DGP); 537-9 (how the model works).

[87] Ex A-43 Sch HH5 (read-only); Ex MEC-72 (working version).

[88] Alvarez Direct, 6 TR 3965-71.

works is provided for context. For every circuit, the "Ckt Info and Calculations" Tab provides the number of historic non-MED (excluding Major Event Days or MEDS) "tree" and "non-tree" outages for 2017 through 2022.[89] The model assigns each circuit a treatment (*e.g.*, Tree Trim or PTMM) in a particular year. Then the model applies either a percentage increase in outage events in years where there is no treatment (degradation) or a decrease in outage events in years in and following program treatment to reflect assumed program benefits.

To illustrate, consider Circuit ARNLD1912 (row 196), a 6.52 mile 4.8kV circuit with 981 customers that was tree trimmed in 2018 and is scheduled again for trimming in 2023, 2028, and 2031; it received PTMM in 2022 and will receive it again in 2035. The model shows this Circuit experienced outage events during non-MED conditions as follows:

Tree Outage Multiple Outage Events						**Non-Tree Multiple Outage Events**					
2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
0	3	0	0	0	3	13	10	4	5	8	16

To this data, the model applies tree trimming benefits to reduce tree outages and PTMM benefits to reduce non-tree outages on this Circuit annually from 2023 through 2036. Then the model multiplies each annual outage event by a Customer Interruptions (CINT) Per Event factor and a Customer Minutes Interrupted (CMINT) Per Event for the period. For Circuit ARNLD1912, because it is 4.8kV, each tree outage results in 70 CINT and 20,166 CMINT; each non-tree outage is 79 CINT and 11,941 CMINT. The model then uses a formula to convert these non-MED CINT and CMINT sums to MED conditions. The model thus relies heavily on the projected outage

[89] Ex MEC-72, Ckt Info and Calculations Tab. The model further divides outage events into non-MED outages into single and multiple categories based on whether the historic outage affected a single customer or multiple customers. The single categories for tree/non-tree are not particularly impactful so largely disregarded in this discussion.

reduction benefits for each program – if outage reductions are inaccurate, multiplying them by the CINT and CMINT factors and the MED conditions factors exacerbates the inaccuracy.

While there are others, a key flaw is that the model's outage reduction benefits projections are unreliable. The benefits projections start with the Company's Reliability Program Analysis, Exhibit A-43 Schedule HH6. A threshold flaw in the Analysis is that, for the limited programs analyzed, only 10 months of data (January to October) annually from 2017 to 2022 were considered. While the analysis was developed in late 2022, it has not been updated to include full-year (12-month) data and 2023 data.[90] DTE relies on the Reliability Model to support substantial increasing reliability-based investments before updating its skimpy Analysis with available data.

Another flaw in the Reliability Program Analysis is that it compares program benefits relative to the year *of* treatment – number of outages the year after a line was trimmed (Year_1) or 2 years after (Year_2) compared to the year trimmed (Year_0), not relative to years *before* trimming (or other treatment).[91] The Reliability Model itself – like the Company's annual Tree Trim evaluations and occasional 4.8kV Hardening evaluations – compares reliability before to reliability after.[92] The Analysis that forms the foundation of benefits projections in the Reliability Model makes no effort to compare before and after treatment, only year of and years after.

By comparing outage events post-treatment (Year 1) to outage events year-of-treatment (Year 0), the Reliability Program Analysis ignores variability associated with weather and other factors.[93] The Reliability *Model* – unlike the Reliability *Program Analysis*– applies outage reduction factors to the 5-year average of outage events pre-treatment – *i.e.*, Tree Trimming

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[90] Kryscynski Cross, 3 TR 561 (explaining why Analysis likely used 10-month data set).

[91] Kryscynski Cross, 3 TR 563.

[92] Ex MEC-4, MEC-70; Andahazy Direct, 6 TR 928-30; Elliott Andahazy Rebuttal, 4 TR 1034.

[93] Alvarez Direct, 6 TR 3969-70.

reduces tree non-MED multiple outages 20% from the 5-year average (2018-2022) of such events; PTMM reduces non-tree non-MED multiple outages 30% from the 5-year average (2018-2022) of such events.[94] But the Analysis, which is the foundation of outage event reduction assumptions in the Reliability Model, does not consider historic circuit performance pre-treatment, it starts in Year 0 and compares future years back to Year 0.[95]

Compounding this curious and inconsistent methodology is the fact that the Reliability Program Analysis ignores potential benefits in the year *of* treatment (Year 0). The Reliability Model assumed treatment (*e.g.*, trimming) occurs mid-year, so benefits are halved in Year 0 in the Reliability Model.[96] But the Reliability Program Analysis assumes no treatment in Year 0 – it is the baseline.[97] Using Year 0 as the baseline is problematic if there was treatment that year, as the model reasonably assumes, and its results thus unreliable. The Reliability Program Analysis thus lacks historic context and overemphasizes events in Year 0.

The Reliability Program Analysis is foundationally flawed by lacking full year data for years included, lacking 2023 data, and ignoring pre-treatment performance and year-of benefits. The way it analyses specific program benefits suffers additional flaws, discussed below.

a. Flaws in Tree Trimming Benefits

The Reliability Program Analysis is not a credible analysis to support the Reliability Model outage reduction benefit assumptions. For tree trimming, the Model assumes these benefits:[98]

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94 Ex MEC-72, Ckt Info and Calculations Tab, col GL (2024 TT reductions relative to 5-year Average Tree Events in col GK); col LF (2024 PTMM reductions relative to 5-year Average Non-Tree Events in col LC).

95 Ex A-43 Sch HH6; Kryscynski Cross, 3 TR 563.

96 Kryscynski Cross, 3 TR 557-8.

97 Kryscynski Cross, 3 TR 563.

98 Ex MEC-72, Benefits Walkdown & Degradation Tab, rows 71-76.

Year 0	1 year after	2 years after	3 year after	4 years after
-20%	-40%	-30%	-25%	0%

These reductions align closely with the Reliability Program Analysis, but they are inconsistent with outage reductions reported by the Company in its annual Tree Trim reports. According to its Tree Trim Annual Reports filed in U-20162, here is what DTE reported for % Change in Outage Event Reduction for ETTP circuits:

	1 year after	2 years after	3 years after	4 years after
2023 (Ex MEC-4 p. 9)	-22%	-12.8%	9.94%	58.1%
2022 (Ex MEC-70 p 9)	-27.3%	-15.2%	9.4%	36.7%
2021 (Ex MEC-70 p22)	-29.3%	-1.0%	2.4%	33.6%
2020 (Ex MEC-70 p 35	-34.0%	-25.7%	-13.8%	-6.3%
2019 (Ex MEC-70 p 50)	-23.0%	-12.3%	1.6%	6.2%
Average	**-27%**	**-13%**	**2%**	**26%**

There are method differences in the Reliability Program Analysis and ETTP annual report analyses – *e.g.*, ETTP annual reports do not compare outages to the single trim year (Year 0) but to the average of 3 years preceding trimming.[99] Even so, five years of ETTP data suggests tree trimming is unlikely to reduce outage events to the extent reflected in the Reliability Program Analysis and Reliability Model, undermining the credibility of both.

b. <u>Flaws in 4.8kV Hardening Benefits</u>

The model's 4.8kV Hardening benefits are similarly unreliable and seemingly inflated:[100]

[99] Ex MEC-70, p. 8.

[100] Ex MEC-72, Benefits Walkdown & Degradation Tab, rows 22-44.

Year 0	1 year after	2 years after	3 years after	4 years after	5 years after	6 years after	7 years after	8 years after	9 years after	10 years after
-40%	-80%	-75%	-70%	-65%	-60%	-55%	-50%	-45%	-40%	-35%

The basis for these assumptions is also the Reliability Program Analysis in Exhibit A-43 Schedule HH6.[101] That analysis again shows only 10 months of annual data for 2017 to 2022 (since there was no hardening in 2017, the analysis is limited to 10-month data for 2018-2022[102]). The analysis compiles annual non-tree event reductions for 10 months for up to 4 years after hardening:

% change in events number of years after program completion

	N+1	N+2	N+3	N+4	N+5	N+6
Raw data calculation	-78%	-79%	-79%	-71.2%	NA	NA
Reliability Modeling (Smoothed)	-80%	-75%	-70%	-65%	-60%	

The sample size for Hardening circuits is notably limited. While 775 lines were included in the Tree Trim analysis, only 72 circuits were included in the Hardening part of the Reliability Program Analysis.[103] For N+4 data (reductions 4 years after hardening), the Analysis included only 5 circuits.[104] DTE SMEs then extrapolated outage reductions over 17 years.[105] It is unclear why the Analysis relies on the small sample – the Reliability Model shows 118 circuits hardened from 2018 through 2021.[106] The Company has not updated the analysis to include 12-month annual data, 2023 data, nor data from more circuits.[107]

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[101] Kryscynski Cross, 3 TR 565-6.

[102] Kryscynski Cross, 3 TR 565.

[103] Ex A-43 Sch HH6.

[104] Kryscynski Cross, 3 TR 565-6.

[105] Ex MEC-72, Benefits Walkdown & Degradation Tab, rows 22 to 45 (showing benefits through Year 17 before degradation resumes in Year 18); Kryscynski Cross, 3 TR 567.

[106] Ex MEC-72, Ckt Info and Calculations Tab, col BJ set to 2018, 2019, 2020, 2021.

[107] Kryscynski Cross, 3 TR 567.

Another problem in the Hardening analysis is the raw data suggests benefits may increase 2 years after hardening, but the Model assumes reducing benefits. For circuits hardened in 2018 and 2020, Year_2 had fewer outages than Year_1 (there is no Year_2 data for 2021):[108]

Hardening

ExMED

2017-2022 10 Months (event volumes)

Year	Year_0	Year_1	Year_2	Year_3	Year_4
2017	0	0	0	0	0
2018	59	14	6	8	17
2019	284	60	62	67	0
2020	515	129	113	0	0
2021	267	44	0	0	0

Other factors (*e.g.*, weather, other outage causes) or limited data sets may explain this seemingly anomalous result; a more robust analysis is warranted.

Not only are the projected benefits from Hardening based on partial year data and a small sample, but the analysis results – 70-80% non-tree outage event reductions in the first 3 years after hardening – are dubious. Though the Company has not presented evaluations of non-MED non-tree outage event reductions associated with 4.8kV circuits post-hardening, other program evaluations undermine the model assumptions. Company witness Elliott Andahazy presented an evaluation of 4.8kV circuits one-year after hardening in all-weather conditions, which shows 38% reductions in event frequency (SAIFI) and 65% in SAIDI one year after hardening.[109] The Company's evaluation of hardened 4.8kV circuits excluding MEDs, comparing 3-year average before and after hardening, showed 44% improvement in all-weather customer interruptions.[110] Neither comes close to the Reliability Program Analysis and Reliability Model assumptions that the 4.8kV Hardening program reduces non-tree ex-MED outages by 70-80% in the first 3 years

[108] Ex A-43 Sch HH6, p. 3.

[109] Elliott Andahazy Direct, 4 TR 928-9.

[110] Elliott Andahazy Rebuttal, 4 TR 917.

after hardening. Moreover, those Company evaluations of Hardening benefits likely exaggerate its benefits by conflating tree trimming and hardening into the same assessment.[111]

Data in the Reliability Model itself further undermines its assumed Hardening benefits. For the 41 circuits hardened in 2020 and 35 circuits hardened in 2021, most performed slightly *worse* the year of and after hardening than the years before hardening – a few might have achieved 40% reductions the year *of* hardening and 80% reductions the year *after* hardening, but most came no-where close:[112]

[111] Elliott Andahazy Rebuttal, 4 TR 1034.

[112] Ex MEC-72, Ckt Info and Calculations Tab, Hardening for 2020 or 2021 in col BJ.

Circuits Hardened in 2020	Outage Events Non-MED Non-Tree Multiple					
	2017	2018	2019	2020	2021	2022
APPOL1142	2	6	4	9	5	5
APPOL1318	6	14	2	27	9	4
CONAT1269	3	2	1	31	1	1
CONAT1293	3	6	3	26	2	0
CONAT1310	2	6	0	8	3	0
CONAT1362	0	15	7	22	8	3
CONAT1446	4	2	4	13	19	3
CONAT1447	7	6	3	10	2	11
CONAT1450	0	3	3	9	0	0
CONAT1451	3	1	3	16	4	3
CONAT2064	3	8	7	24	5	5
CONAT2235	6	6	8	27	3	6
CRTIS1330	3	7	3	6	1	0
CRTIS1332	12	4	0	0	0	0
CRTIS1337	3	5	3	9	3	2
CRTIS1410	5	4	3	16	6	8
CRTIS2031	1	7	4	4	10	9
CRTIS2098	4	9	3	18	1	5
CRTIS2104	1	14	2	12	2	7
HAWTH1853	6	5	0	23	25	9
HAWTH1968	4	4	3	23	9	5
HAWTH2112	5	4	11	10	5	5
TIRMN1102	4	10	2	31	4	4
TIRMN1191	4	6	2	0	0	0
TIRMN1196	1	10	6	5	4	6
TIRMN1223	3	12	3	17	4	2
TIRMN1255	4	6	6	17	2	5
TIRMN1368	3	8	3	22	1	2
TIRMN2093	2	8	4	22	10	5
TIRMN2144	10	6	4	16	11	4
TURNR1000	1	3	0	26	1	1
TURNR1001	16	8	4	0	0	0
TURNR1114	9	16	7	14	6	3
TURNR1143	6	4	4	30	2	1
TURNR1144	5	8	7	27	6	6
TURNR1147	5	3	3	38	1	5
TURNR1148	2	1	5	30	17	7
TURNR1189	10	10	7	26	4	6
TURNR1220	1	7	6	7	4	5
TURNR1477	2	2	9	26	5	8

Circuits Hardened in 2021	Outage Events Non-MED Non-Tree Multiple					
	2017	2018	2019	2020	2021	2022
CHIGO0434	1	0	0	1	7	7
CHIGO1415	4	0	1	5	23	0
CHIGO1439	3	5	5	3	25	2
CHIGO1448	7	13	2	8	2	12
CHIGO1463	3	2	4	1	42	3
CHIGO1584	4	6	15	8	5	42
CHIGO2072	3	5	1	1	9	2
CHIGO2081	4	2	0	2	18	1
FLANE1831	1	6	7	1	3	0
FLANE1835	3	0	6	4	9	17
FLANE1839	10	4	4	2	12	17
FLANE1840	16	6	9	6	18	9
GARY 1365	1	1	4	9	5	27
GARY 1407	7	2	3	2	16	0
GARY 1431	1	1	0	0	0	0
GARY 1858	1	2	1	1	3	2
GARY 1920	6	2	0	1	3	1
GARY 2115	2	3	3	3	19	1
GRANT0369	0	0	0	0	0	0
GRANT1291	0	1	2	0	7	3
GRANT1306	3	4	6	15	26	4
GRANT1494	5	7	4	6	22	1
GRANT1582	4	3	1	0	14	5
GRANT1598	5	4	4	5	3	28
GRANT2195	2	3	0	4	27	3
GRANT2233	2	6	9	3	19	9
HAWTH0316	0	0	0	0	0	1
HAWTH1176	4	5	6	3	31	7
HAWTH1261	4	3	9	5	17	4
HAWTH1289	15	10	8	1	39	6
HAWTH1301	0	0	0	0	0	0
HAWTH1392	0	5	1	0	22	5
HAWTH1841	7	6	5	5	40	9
HAWTH2020	4	6	5	9	43	4
HAWTH2071	3	2	2	13	17	5
AVERAGE	**5**	**4**	**4**	**4**	**13**	**9**

TURNR2165	6	12	10	21	5	9	
AVERAGE	**4**	**7**	**4**	**18**	**5**	**4**	

The Reliability Program Analysis results for 4.8kV Hardening are not credible, and they do not support projected benefits many years after Hardening. Moreover, as discussed at length by Mr. Alvarez and by MNSC witnesses in prior cases, most of the benefits from Hardening are likely resulting from tree trimming, which is the first stage of Hardening, as opposed to cross-arm replacement and other equipment replacements involved in Hardening.[113]

c. Flaws in PTMM Benefits

The projected PTMM benefits in the Reliability Model are particularly unreliable. Here are modelled outage reductions for circuits treated with PTMM in "2023+":[114]

Year 0	1 year after	2 years after	3 years after	4 years after	5 years after	6 years after	7 years after	8 years after	9 years after
-15%	-30%	-26%	-22%	-18%	-14%	-10%	-6%	-8%	-2%

One problem with the Model's PTMM benefits is it is internally contradictory. It purports to apply PTMM benefits (reductions) for PTMM circuits starting in 2023 ("2023+") and no benefits (0%) for PTMM circuits before 2023 ("pre 2023/enhanced specs").[115] According to Mr. Kryscynski, this pre-2023 / 2023+ distinction in PTMM benefits reflects "a change in the PTMM program" – a "transformation" similar to pre-ETTP / post-ETTP for trimming.[116] But the model is contradictory because, while the model labels 202**3** as the pivotal PTMM year, the model treats

[113] Alvarez Direct, 6 TR 3930-1, 3951, 3966-9.

[114] Ex MEC-72, Benefits Walkdown & Degradation Tab, rows 114-131.

[115] Ex MEC-72, Benefits Walkdown & Degradation Tab, row 3, 114.

[116] Kryscynski Cross, 3 TR 569.

202**2** as pivotal. The model applied no PTMM benefits to circuits treated in 202**1** but applied PTMM benefits to circuits treated in 202**2** and 2023:

- For the 67 circuits with PTMM in 2021, none have PTMM Improvements for 2023 through 2036.[117]
- For the 151 circuits with PTMM in 2022, all have 30% improvement in 2023, 26% in 2024, 22% in 2025, and so on, per the Model's PTMM "2023+" benefits.[118]
- For the 62 circuits with PTMM in 2023, all have 15% improvements in 2023, 30% in 2024, and so on.[119]

This indicates internal confusion or error in the model or its users by describing PTMM benefits inaccurately. It further indicates the model could be used to validate the assumed PTMM benefits on circuits that received PTMM in 2022 using historic (actual) 2023 outage data. The Reliability Model presented in this case was not updated to include 2023 outage data (it provides outage data 2017-2022). It could and should be updated to include 2023 data and to validate 2022 PTMM circuits' projected non-tree outage events.

In addition, the assertion that 2023 (or even 2022) was pivotal for PTMM because of "enhanced specifications" is also suspect because DTE updated PTTM pole and pole top specifications in 2019.[120] Since then, DTE has followed consistent pole and pole top technical specifications, with subsequent PTMM modifications to inspection processes – specifically, DTE eliminated Joint Use inspections and committed to more "stringent adherence to PTMM standards

[117] Ex MEC-72, Ckt Info and Calculations Tab, col BH (2021), columns HA to HM (PTMM Improvement/Degradation).

[118] Ex MEC-72, Ckt Info and Calculations Tab, col BH (2022), columns HA to HM (PTMM Improvement/Degradation); see also Benefits Walkdown & Degradation Tab lines 114-31 (2023+ benefits).

[119] Ex MEC-72, Ckt Info and Calculations Tab, col BH (2023), columns HA to HM (PTMM Improvement/Degradation).

[120] Elliott Andahazy Direct, 4 TR 948-9; Ex A-23 Sch M9 (Wood Pole Maintenance Specification); Ex A-23 Sch M10 (Pole Top Maintenance Specification); Elliott Andahazy Cross, 4 TR 1083-6.

and enhanced quality controls" starting in 2022.[121] DTE has not evaluated reliability benefits on PTMM circuits since the 2019 enhanced specifications.[122] By making administrative modifications to PTMM inspections and invoking them as basis to disregard pre-2023 (or 2022) PTMM data, DTE avoids accountability for historic PTMM investments.

The foundation for projected PTMM benefits – the Reliability Program Analysis – only indirectly supports the reduction assumptions.[123] Instead of looking at PTMM benefits, the Reliability Program Analysis used the Customer Excellence (CE) program as a proxy for PTMM.[124] The Company did not support that these programs are comparable or show they produce comparable results. But even if comparable to PTMM, the Reliability Program Analysis supporting CE benefits does not support the Reliability Model benefits. The Analysis is based on partial year data (January through October), and for the CE analysis, it had only 3 years of data – even less than Hardening.[125] Moreover, the Analysis shows inconsistent results between the Raw and "Smoothed" data:

% change in events number of years after program completion

	N+1	N+2	N+3	N+4	N+5	N+6	N+7
Raw data calculation	-13%	-21%	-31%	0.0%	NA	NA	NA
Reliability Modeling (Smoothed)	-30%	-25%	-20%	-15%	-10%	-5%	0%

The Raw data suggests CE resulted in limited benefits the first year after treatment but growing annual benefits the following two years. There is no data after Year 3 – Company SMEs extrapolated later year reductions.[126] The Smoothed data deviates substantially from Raw data – a

[121] Elliott Andahazy Direct, 4 TR 950-1.

[122] Elliott Andahazy Direct, 4 TR 948-9; Elliott Andahazy Cross, 4 TR 1091-3.

[123] Ex A-43 Sch HH6.

[124] Ex A-43 Sch HH6 p. 4; Kryscynski Cross, 569-70.

[125] Ex A-43 Sch HH6.

[126] Kryscynski Cross, 3 TR 575.

13% average reduction in Year 1 becomes a 30% reduction – a decision made by Company SMEs using the raw data as a "rough guide" to smooth over "this noisier data," potentially reflecting weather variability or the small data set.[127] The Smoothed data is also directionally inconsistent with Raw data for CE circuits – Raw data has increasing outage events in successive years; Smoothed data is the opposite. There is another leap from "Smoothed" Reliability Program Analysis for CE to the Reliability Model for PTMM – the Analysis assumed benefits through Year 5, going down in increments of 5%, but the Reliability Model spread the PTMM benefits through 9 years after treatment. There is no support nor explanation for these assumptions.

At bottom, notwithstanding that DTE has been adhering to enhanced PTMM construction specifications since at least 2020, there is no credible analysis supporting PTMM projected benefits in the Reliability Model. While the Company recognizes the need to monitor the data every year to improve the analysis and has full year data through 2023, DTE has not yet updated the analysis.[128]

Moreover, the model's projected PTMM benefits are facially suspect. Preemptively replacing technically-"defective"-but-actually-functioning[129] pole and pole-top equipment appears unlikely to reduce all non-tree outage events 30% the first year after replacement. The Reliability Model undermines the credibility of projected PTMM benefits. According to the model, 67 circuits received PTMM in 2021; most performed worse the year after PTMM (2022) than the preceding

[127] Kryscynski Cross, 3 TR 572-3.

[128] Kryscynski Cross, 3 TR 573-4.

[129] The Emergent Replacement Storm and Non-Storm programs address failed pole and pole top equipment. As discussed below regarding the PTMM investment plan, PTMM inspects for latent equipment "defects" for preemptive replacement.

years – on average, PTMM circuits had more non-tree multiple ex-MED outage events after PTMM than before:[130]

CIRCUIT	Outage Events Non-MED Non-Tree Multiple 2017	2018	2019	2020	2021	2022
ALNPK1284	11	3	3	5	5	2
ALNPK2090	3	2	8	1	6	5
ANDER0311	3	0	0	0	1	0
ANDER0312	7	3	5	2	8	7
CAMDN8276	16	24	18	24	16	28
CAMDN8284	1	6	10	13	24	12
COLUM0304	2	2	12	10	14	30
DERBY2604	0	6	2	4	23	5
DIMND9866	10	19	36	21	16	27
DIMND9875	26	21	30	21	14	33
DISCO8090	33	48	8	3	2	1
ELKTN0302	3	11	6	9	14	17
FAWN 8813	0	1	1	2	1	1
FGROV0302	6	2	1	4	4	29
FIFMI1002	1	2	0	2	4	5
FLMNG8256	4	15	12	15	11	18
FRLDG0302	4	2	3	10	8	4
FRLDG0303	2	3	2	12	10	4
GRAYL8517	9	11	21	17	15	20
GRAYL8539	4	10	7	14	12	18
GRAYL8540	2	16	13	12	6	15
GULLY1998	1	8	3	7	8	17
HIKRY9104	3	11	14	27	22	56
HILL 0364	4	4	6	3	4	5
HILL 2590	9	6	7	3	4	0
JEFSN9415	4	2	1	1	6	3
JEFSN9418	14	9	4	5	13	6
KEEGO0311	5	1	0	2	0	2
KILGR8772	12	20	23	108	19	9
LNGLK8977	5	7	4	7	8	2
LOCDL8918	11	17	18	18	10	14
MILTN0301	3	4	0	3	5	1
MILTN0302	2	5	2	6	21	5
MOHAK1915	13	13	13	13	13	13
NANKN2828	2	7	6	11	19	5
NBOST0305	7	7	7	5	11	3
NBOST0306	1	2	0	6	6	3
NRBRN2606	4	1	2	3	8	3
NRBRN2655	3	0	5	3	4	2
OTIS 8615	22	14	16	13	19	26
OTIS 8666	13	12	7	16	7	14
OXFRD8074	11	5	15	24	24	14
ROCKW0955	0	0	0	0	0	0
ROCKW2845	2	4	2	2	9	6
ROCKW2846	1	1	3	0	7	2
SAVAN1005	2	0	0	0	0	3
SAVAN1088	3	1	2	6	4	13
SOFLD9010	11	8	18	11	14	12
VILLA0470	0	1	0	0	0	0
VILLA0636	1	5	1	1	1	19
VILLA1359	0	5	4	5	3	33
VILLA1552	1	1	1	6	3	18
VILLA1553	3	0	1	4	1	100
VILLA1555	2	5	4	2	7	42
VILLA1556	4	0	2	1	2	60
VILLA2029	2	0	0	0	3	10
VILLA2161	8	6	3	6	3	22
WAYBN2092	2	3	7	7	4	16
WDSID0844	0	1	0	0	0	1
WDSID1150	1	6	2	4	7	5
WDTRK0021	2	0	0	1	1	0
WDTRK0022	0	0	0	0	0	0
WDTRK0320	1	1	2	5	5	0
WILSN8101	9	15	11	27	20	19
YATES0311	6	6	8	7	7	5
YPSIL0011	1	1	2	0	1	0
YPSIL0302	6	4	3	3	5	3
AVERAGE	**5**	**7**	**6**	**9**	**8**	**13**

[130] Ex MEC-72, Ckt Info and Calculations Tab, col BH (PTMM 2021), showing columns L to Q (Outage Events / Non-MED / Non-Tree / Multiple / 2017-2022).

This data also suggests the model assumption that PTMM reduces non-tree outage events 15% in the *year of* treatment relative to the 5-year average preceding trimming is dubious.[131] For the 67 circuits with PTMM in 2021, over the 4 years pre-PTMM, they averaged 6.75 non-tree ex-MED multiple outage events pre-PTMM[132] and 8 such events the year of PTMM – an 18% *in*crease, not 15% *de*crease.

As mentioned, the Reliability Model applied PTMM benefits to circuits with PTMM in 2022 – it projects 30% fewer non-tree multiple ex-MED outage events in 2023, 26% fewer in 2024, and so on.[133] Per the model's PTMM benefit for Year 0, 2022 PTMM circuits are projected to have 15% fewer non-tree multiple ex-MED outage events in 2022 compared to the 5-year average preceding Year 0.[134] But the Reliability Model shows that, on average, 2022 PTMM circuits had 7.4 *more* non-tree multiple ex-MED outage events in 2022 than the 5-year average pre-PTMM – a 121% ***in***crease in such events in Year 0 of PTMM:[135]

Outage Events Non-MED Non-Tree Multiple					
2017	**2018**	**2019**	**2020**	**2021**	**2022**
6	6	6	7	8	**14**
5-year average 2017-2021					6.6

While not definitive, the historic data in the Reliability Model suggests PTMM may not produce significant and sustained reductions in non-tree ex-MED outages. Until DTE actually

[131] Ex MEC-72, Benefits Walkdown & Degradation Tab, row 116, PTMM Year 0 benefits 15%.

[132] Average of 5 + 7 + 6 + 9 = 6.75.

[133] Ex MEC-72, Ckt Info and Calculation Tab, see e.g., row 21 (ADAIR0321) columns HA to HN, columns LE to LR (reduced events).

[134] Ex MEC-72, Benefits Walkdown & Degradation Tab, row 116, PTMM Year 0 benefits 15%.

[135] Ex MEC-72, Ckt Info and Calculation Tab, column BH (PTMM 2022); average of columns L to Q (Outage Events / Non-MED / Non-Tree / Multiple / 2017-2022).

assesses PTMM benefits, projections of PTMM benefits are speculative and do not support increasing spending.

d. Flaws in Conversions, Distribution Automation Benefits

For conversions of 4.8kV lines to 13.2kV, the Reliability Model assumes 90% reductions in non-tree non-MED outages annually for 10 years, with continuing benefits gradually reducing to 65% 20 years after conversion.[136] The Company provided no workpaper supporting these assumptions.[137] The witness supporting the 90% reductions from conversions testified these projects are expected to result in "*up to* 90%" reductions,[138] which is much different than the model's 90% across the board for 10 year reductions. The Company was unable to identify a source analysis for the "up to 90%" estimate, offering instead a vague analogy to a 65% reliability improvement in the hardening program.[139]

Distribution Automation benefits come from DTE SMEs and the Distribution Automation Benefits Model, which is a CEII Confidential exhibit.[140] According to the Reliability Model, on circuits where Distribution Automation is applied, Customer Interruptions would reduce 18% or 36% in Scheme 1 and 39% in Scheme 7.[141] As discussed below in the section opposing the Company's proposed Distribution Automation spending increases, these assumed benefits of Distribution Automation lack foundation in DTE's experience with automation and in actual

[136] Ex MEC-72, Benefits Walkdown & Degradation Tab, rows 47-69.

[137] See Ex A-23 Sch HH6.

[138] Deol Direct, 5 TR 1144; Deol Rebuttal, 5 TR 1227.

[139] Ex MEC-78, p. 2.

[140] Kryscynski Cross, 3 TR 578; Ex A-53 Sch RR2 (CEII Distribution Automation Prioritization mode).

[141] Ex MEC-72, Automation Benefits by Ckt Tab, columns C, F. Some circuits have lesser reductions in Scheme 7.

historic reliability data; they are projections based on subjective, unproven assumptions from DTE staff and consultants for a program in its infancy.[142]

In short, the heart of the Reliability Model is the outage reduction assumptions for each of the six programs modeled, and those assumptions are highly speculative. DTE might have validated the non-tree non-MED multiple outage reduction after treatment compared to 5-years of pre-treatment outages on circuits actually trimmed, hardened, or treated with Customer Excellence or PTMM, but it has not. DTE might have compared its projected 2023 SAIDI and SAIFI Excluding Major Event Days to actual 2023 SAIDI and SAIFI Ex MEDs, but it has not. The results of the Reliability Model are thus, ironically, unreliable.

e. Other Reliability Model flaws

There are at least three additional flaws in the Reliability Model. *First*, the model effectively classifies outages caused by non-trees as being caused by equipment failures. The Outage Management System identifies outage causation, and that is the source of the Reliability Model tree- and non-tree events.[143] The model collects all "non-tree" outage events to include all outage causes except tree.[144] As a result, the Reliability Model combines all the following cause categories as "non-tree": Equipment, Unknown, Intentional, Animal, Other, Public Interference, Weather, Loading, Customer.[145] The model applies PTMM, Hardening, and Conversion benefits to reduce all these "non-tree"-caused outage events.[146] It is unreasonable to project PTMM – by replacing broken cross-arms, obsolete insulators, and split poles – will reduce outages caused by

[142] Per Ex MEC-65, DTE installed reclosers on a single circuit in 2022 and it is too soon to assess post-installation reliability data for circuits with reclosers installed in 2023.

[143] Ex MEC-35; Kryscynski Cross, 546-7.

[144] Kryscynski Cross, 3 TR 543-4.

[145] Kryscynski Cross, 3 TR 543-4, 569.

[146] Kryscynski Cross, 5 TR 569.

"Intentional" activity or "Animal[s]" or "Public Interference", which caused 16.3% of non-MED customer interruptions from 2019 to 2023.[147] It is not credible that Hardening will reduce 80% of outages caused by Animals, Unknown, Public Interference, Intentional, Weather, Loading, and Customer activities. PTMM, Hardening, and Conversions may reduce equipment-caused outages since these are programs that replace equipment (the extent of equipment-caused outage reductions has not been evaluated). DTE analyses show Equipment causes a fraction of outages – 33.2% of SAIFI (ex-MEDs), 20.8% of outage events (including MEDS).[148] By lumping outages caused by everything except trees together and assuming equipment replacement programs will reduce outages caused by all non-tree causes, including non-equipment causes, the analysis over-projects outage reduction benefits of PTMM, Hardening, and Conversions and skews the Reliability Model results.

__Second__, the model unreasonably assumes there will be 8% more non-tree outages on a circuit annually, absent PTMM, Hardening, or 4.8kV Conversion.[149] DTE presented a Degradation Analysis to support this assumed degradation.[150] The analysis considers 2008 to 2017 data showing a degradation trend line approaching 8%. This baseline analysis pre-dates the ETTP program and reflects a period when there was little capital or strategic investment in the system.[151] The Reliability Model applies the 8% degradation assumption to both tree and non-tree outages.[152] There is no analysis supporting the assumption that, but-for PTMM, Hardening, or 4.8kV Conversion, a circuit will experience 8% more non-tree outage events annually excluding major

[147] Kryscynski Rebuttal, 3 TR 411.

[148] Kryscynski Rebuttal, 3 TR 411; Ex A-23 Sch M8 (2023 DGP), p. 42 of 274.

[149] Kryscynski Direct, 3 TR 362; Ex MEC-72, Benefits Walkdown & Degradation Tab, rows 3-7, columns H-J; Kryscynski Cross, 3 TR 579.

[150] Ex MEC-67.

[151] Kryscynski Cross, 3 TR 580.

[152] Kryscynski Cross, 3 TR 581.

event days, as the Reliability Model assumes. For example, the model projects a circuit without PTMM, Hardening, or Conversion increases from an average of 8 up to 12 non-tree outages between 2023 and 2028.[153] The model could readily validate this assumption or develop a better assumption using historic non-tree outage data on circuits without Hardening, PTMM, or Conversion. The degradation assumption is further undermined by the fact that DTE claims to be committed to ETTP – even improving it – and it must inspect and maintain cycles. The assumption that the baseline for all programs is 8% degradation annually is unsupported and unreasonable.

Third, the model converts outages to customer interruptions and customer-minute-interruptions using circuit averages not actual circuit conditions or customers.[154] Instead of projecting CINT and CMINT using the number of customers on a circuit, the model assumes average CINT and CMINT based on voltage type.[155] Thus, the model fails to evaluate relative contributions from PTMM, Hardening, or Conversion on a circuit with 1,000 customers versus a circuit with 100 customers. This prevents the model from considering increasing reliability benefits sooner and at lower costs through targeted program deployment.

There are undoubtedly other flaws in the Reliability Model – it is complex and was produced for the first time in this proceeding. It clearly offers multiple opportunities for refinement and improvement. At bottom, the outage reduction benefits should be updated with complete and comprehensive data and validated. As presented in this case, the Reliability Model fails to support the reasonableness and prudence of proposed spending in the six strategic capital programs addressed in the model.

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[153] Ex MEC-72, Ckt Info and Calculation Tab; *see, e.g.*, row 18 (ACME 9485), columns LE to LJ.

[154] Kryscynski Cross, 3 TR 583-5; Ex MEC-72, Ckt Info and Calculations Tab, columns UP-VC (non-MED tree CINT), columns VK-VW (non-MED non-tree CINT).

[155] Ex MEC-72, Assumptions by Voltage Tab; Kryscynski Cross, 3 TR 584-6.

iii. DTE Electric's strategy of massively increasing distribution capital spending on equipment replacement programs is misguided.[156]

The Company proposes to fix its poor reliability by mostly replacing old equipment. Distribution capital tripled from around $500 million from 2015-2017 to over $1.5 billion in 2024;[157] the 2023 DGP proposes nearly $5 billion in "strategic capital programs" 2024-2028.[158] In this single case, the Company requests approval for almost $4 billion in "strategic capital" programs:[159]

2023	**2024**		**2025**		**2026**	**2027**
Rate Base	**Rate Base**	**IRM**	**Rate Base**	**IRM**	**IRM**	**IRM**
$801.026 million	$708.777 million	$61.865 million	$827.280 million	$290.134 million	$530.000 million	$720.000 million

AG-MN witness Alvarez observed DTE reliability has worsened while distribution plant additions increased:[160]

[156] MNSC believes the record on this issue is the following:

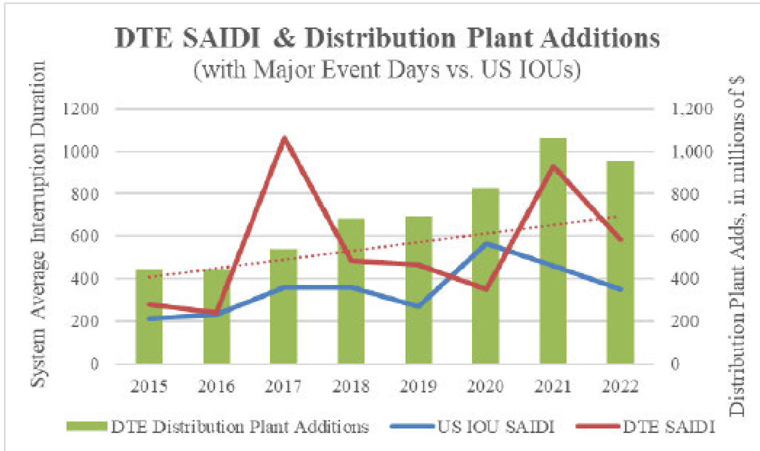
- Direct Testimony of DTE witness Allen J. Kryscynski, 3 TR 304-17, 322-46; Rebuttal Testimony of A. Kryscynski, 3 TR 399-418;
- Direct Testimony of DTE witness Neal T. Foley Direct, 2 TR 70-5;
- Rebuttal Testimony of DTE witness Morgan Elliott Andahazy, 4 TR 909-11;
- Ex A-23 Sch M8; Ex A-12 Sch B5.4; Ex A-33 Sch X1; Ex A-43 Sch HH1, HH2, HH3; Ex A-51 Schs PP1-PP8;
- Direct Testimony of AG, MEC & NRDC witness Paul Alvarez, 6 TR 3923-43;
- Ex MEC-2, 11, 12, 13, 15.

[157] Alvarez Direct, 6 TR 3924.

[158] Ex A-23 Sch M8, p. 162 of 274.

[159] Ex A-12 Sch B5.4, line 22; Ex A-33 Sch X1 line 8.

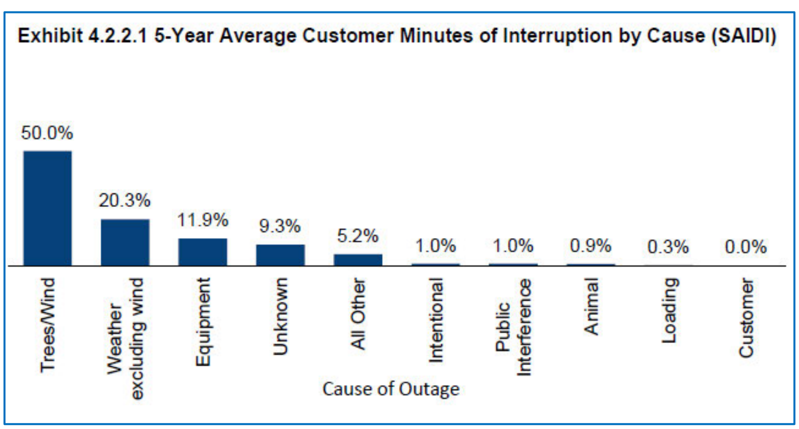
[160] Alvarez Direct, 6 TR 3931.



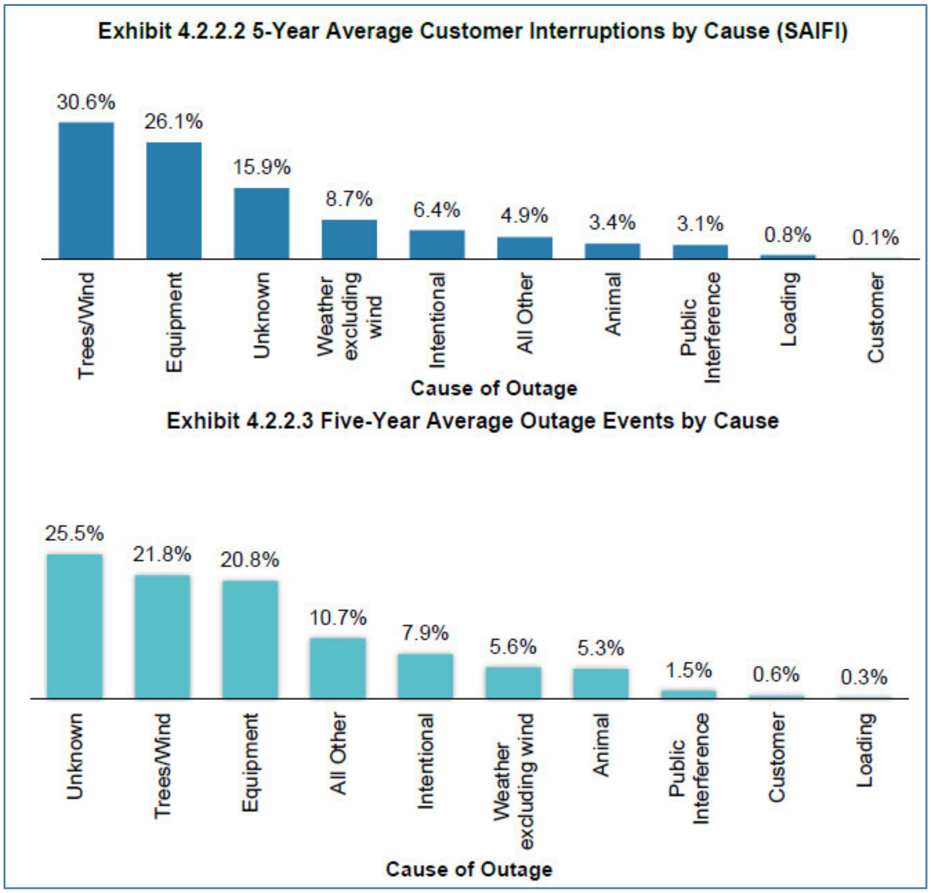
Both Mr. Alvarez and Mr. Stephens noted the 2023 DGP blames trees/wind as the leading cause of outages:[161]

> Tree/wind interference is the leading cause of DTEE's customer minutes of interruption (SAIDI) and number of customer interruptions (SAIFI). Tree/wind is also the leading cause of outage events (within DTEE's Outage Management System) on the DTEE system. Equipment failures are the second leading cause of the SAIFI outage events on the DTEE system.

In support, the 2023 DGP presents three charts showing Trees/Wind as the lead cause across 3 metrics:



[161] Alvarez Direct, 6 TR 3932-3; Stephens Direct, 6 TR 3991; Ex A-23 Sch M8, pp. 41-42 of 274 (2023 DGP).



Mr. Kryscynski rebutted the 2023 DGP analysis with a new analysis suggesting Equipment is the lead cause when considering the subset of data that excludes MEDs and a different period (2019-2023 versus 2018-2022).[162] MNSC renew the request that the Commission strike this improper rebuttal.[163]

[162] Kryscynski Rebuttal, 4 TR 411; Ex MEC-32.

[163] Case No. U-21534, Aug. 23, 2024, Motion to Strike filed by Attorney General, MEC and NRDC; argument and ALJ ruling at 2 TR 53-57; Case No. U-21534, Apr. 26, 2024, Scheduling Memo ("Proper rebuttal evidence is the evidence given by one party to contradict, explain, or disprove evidence produced by the other party and tending to directly weaken or impeach that evidence. It should not be used for the purpose of rehabilitating or supplementing a party's direct case. Rebuttal should also be concise and to the point, presented for the purpose of rebutting specific facts or judgments of the other parties that could not have been reasonably done in a party's direct case."); Case No. U-16034-R, March. 8, 2012, Order, pp 9-10 ("Evidence which could have been offered in a party's main case may be rejected if offered as rebuttal evidence…"); Case No. U-16794, June 7, 2012, Order, pp 4-5 and 6 TR 1432-33 (ALJ ruling striking rebuttal testimony by utility witness as it "is more of an attempt to supplement the Company's case in chief, that is to provide support for its own expenditures than it does rebut the basis of Staff's adjustment…).

Putting aside the impropriety of the new analysis, it changes nothing. At most, it suggests that 33.2% of outages on non-MED days were from equipment while most outages (76.%) are not caused by equipment. It addresses only the customer interruptions (SAIFI), not the number of events or customer minutes interrupted (SAIDI). Its foundation is suspect - Mr. Stephens pointed out that outage field crew notes do not support the classification of many outages as being caused by "equipment."[164] While Mr. Kryscynski in rebuttal asserts those field notes "are not intended to document the cause of outages," he does not dispute that the field notes fail to support the classification cause as equipment in the outage management system.[165]

The new analysis does not support the proposed spending plan, but it does highlight the need for DTE to accurately document outage classifications to identify equipment failure. Even if 33.2% of all non-MED customer interruptions are caused by "equipment," that provides no useful data to assess the efficacy of replacing wooden crossarms or upgrading poles or swapping out porcelain insulators and cutouts. DTE presents no data (besides field notes, disavowed in rebuttal) identifying failed "equipment" nor necessarily the age or condition of unidentified equipment. The Company requests approval for a multi-billion-dollar investment plan premised largely on equipment replacement despite failing to collect – let alone evaluate – data on the root cause of equipment-caused outages. Massive capital investments are premature before DTE collects then evaluates equipment failure data to support capital programs aimed at preemptively replacing equipment supposedly on the verge of failure.

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[164] Stephens Direct, 6 TR 3991; Ex MEC-12.

[165] Kryscynski Rebuttal, 4 TR 410.

Mr. Alvarez also cited research finding no correlation between distribution "capital" spending increases and reliability the year after.[166] However, as DTE witness Kryscynski pointed out, the study evaluated utility "T&D spending" without definition, though another report from the same study suggested T&D is "O&M" spending.[167] The study is ambiguous as to what type of spending is included it also notes *capital* investments to replace distribution equipment increases "T&D spending."[168] The study concludes that "T&D spending was not significantly correlated with interruption frequency or duration."[169] It further acknowledged the potential for increased spending without benefit:[170]

> [A] proactive utility may anticipate future reliability problems and then justify investing a large amount of capital now to reduce the likelihood of a future interruption. In this case, the utility would have higher (lagged) T&D spending and a relatively lower SAIDI and/or SAIFI. Alternatively, a reactive electric utility simply spends more on operations and maintenance as reliability problems arise. In this case, the utility would have higher (current year, not lagged) T&D spending and a relatively higher SAIDI and/or SAIFI. However, it is certainly possible that proactively investing in a new line may increase future utility exposure while not necessarily improving existing system reliability.

The DTE trend show higher lagged (historic), current, and future spending together with high SAIDI and SAIFI, perhaps reflecting costly programs that preemptively replace functional equipment without proving actual reliability benefits.

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[166] Alvarez Direct, 6 TR 3930 (citing Larsen PH, LaCommare KH, Eto JH, and Sweeney JL. *Assessing Changes in the Reliability of the U.S. Electric Power System*. Lawrence Berkeley National Laboratory report LBNL-188741 (August 2015), pp. 37-38).

[167] Kryscynski Rebuttal, 4 TR 409-410; Ex MEC-30 (citing Ex A-43 Sch HH3, Tables A.4, A.5).

[168] Ex A-43 Sch HH3, p. 65 ("For example, a proactive utility may anticipate future reliability problems and then justify investing a large amount of capital now to reduce the likelihood of a future interruption. In this case, the utility would have higher (lagged) T&D spending and a relatively lower SAIDI and/or SAIFI. Alternatively, a reactive electric utility simply spends more on operations and maintenance as reliability problems arise. In this case, the utility would have higher (current year, not lagged) T&D spending and a relatively higher SAIDI and/or SAIFI. However, it is certainly possible that proactively investing in a new line may increase future utility exposure while not necessarily improving existing system reliability.").

[169] Ex A-43 Sch HH2 p 64.

[170] *Id.* at 65.

In sum, the Company's focus on equipment replacement is not well supported with proven benefits to support further increases in equipment replacements.

3. Infrastructure Resilience and Hardening

i. 4.8kV Hardening[171]

Although the Company proposed in U-21297 a substantial spending *de*crease on 4.8kV Hardening in 2024 from $80 million in 2023 to $0 in 2024 ($6.7 million in the test year ending 11/30/2024),[172] DTE changed course in this case. Now, DTE proposes $80 million in 2024 and $125 million in 2025 for 4.8kV Hardening.[173]

Before discussing the record in this case, this brief addresses the regulatory context for this program. In Case No. U-20836, the Company presented its Hardening program, including the results of its roll-out in 2018 through 2020 and investment plan going forward, supporting the investment with an analysis of benefits.[174] MNSC criticized the Company's methodology for evaluating Hardening benefits:[175]

> [MNSC witness Ozar] also looked at the analysis the company presented to support the reasonableness and prudence of the hardening program expenditures. Mr. Ozar concluded that DTE's studies comingled the effects of line clearing and the capital replacements in the program, and that worsening data for the control group did not control for the effects of tree trimming, but likely reflected no tree trimming within many years:

[171] MNSC believes the record on this issue includes the following:

- Direct Testimony of DTE witness Morgan Elliott Andahazy, 4 TR 913-32; Rebuttal Testimony of M. Elliott Andahazy, 4 TR 1098-2044;
- Ex A-23 Sch M8, M12; Ex A-12 Schs B5.4, B5.4.8; Ex A-23 Sch M5; Ex A-51 Sch PP9;
- Direct Testimony of AG, MEC & NRDC witness Dennis Stephens, 6 TR 3993-8;
- Exs MEC-4, 11, 13, 42-54, 58, 70, 74.

[172] Case No. U-21297, Ex A-12 Sch B5.4 p. 8 line 12.

[173] Ex A-12 Sch B5.4, p. 13 line 12.

[174] Case No. U-20836, September 19, 2022, PFD, pp. 80-82.

[175] Case No. U-20836, September 19, 2022, PFD, p. 180 (internal citations omitted).

> I reviewed detailed data provided by the Company in response to discovery regarding the last time the circuits in the control group were trimmed. Of the 55 circuits in the control group for which DTE provided last trim data, 42 had not been trimmed since 2012 or earlier; 8 were last trimmed in 2014; 3 were trimmed in 2015; and 2 were trimmed in 2019. None are scheduled to be trimmed again until 2022 or later. All 28 of the hardened circuits were trimmed in 2019 or later. Comparing reliability differences between the control group circuits, 76% of which had not been trimmed for at least 9 years by the "1-year after" period, to hardened circuits that had all been trimmed within 2 years of the "1-year after" period, is demonstrative of the value of trimming and not much else.

In U-20836, the ALJ agreed that the Company's assessment was significantly deficient for failing to "adequately control for tree-trimming."[176] The Commission did not address the Company's assessment directly but ordered a technical conference in the first quarter of 2023 to assess program spending, benefits, and alternatives.[177]

DTE filed Case No. U-21297 ahead of the Technical Conference, which was held the last week of the first quarter of 2023.[178] The Company proposed to essentially abandon the program in the test year with no 2024 spending.[179] Staff responded to the Company's proposal by raising concerns about safety associated with arc wire the Company's slow pace of removal, and the ALJ concurred, noting the Company presented no real plan to complete arc wire removal.[180] The ALJ further agreed with concerns about the efficacy of Hardening, but noted "DTE also appears to be

[176] *Id.* at 192-193.

[177] Case No. U-20836, November 18, 2022, Order, pp. 92-93.

[178] Case No. U-21297, filed February 10, 2023. The Technical Conference was held March 22, 2023. Ex A-23 Sch M12.

[179] Case No. U-21297, October 5, 2023, PFD, p. 233; Case No. U-21297, Ex A-12 Sch B5.4.

[180] *Id.* at 233-240.

abandoning the program without responding to the critiques."[181] Given the safety and efficacy concerns, Company abandonment, non-completion of the Commission-ordered assessment in U-20836, a new DGP, and the pending distribution audit, the ALJ recommended rejecting spending and instead consider ways to expeditiously remove arc wires.[182]

The Commission in U-21297 also noted that Company's spending plan included $73.3 million bridge spending decreasing to $6.7 million in the test year and – notwithstanding the ALJ recommendation – approved it.[183] It recognized the Technical Conference "could not be incorporated into this record" because of timing but found "completing this work is crucial to the residents and businesses located in areas that contain abandoned arc wire and the Commission agrees with the Staff that the removal of the arc wire should be going faster."[184] The Commission found Hardening "expensive" yet faster than conversion, asked for additional perspective on Company plans and EJ considerations, and emphasized the need to assess potential safety aspects of arc wire removal.[185]

Based on the Commission's Order, DTE reinvigorated Hardening but presented no plan to complete arc wire removal.[186] The 4.8kV Hardening investment plan is as follows:[187]

12 mos. ended 12/31/2022	**12 mos. ending 12/32/2023**	**12 mos. ending 12/31/2024**	**12 mos. ending 12/31/2025**
$157.482 million	$127.010 million	$80.000 million	$125.000 million

[181] *Id.* at 240.

[182] *Id.* at 240-3.

[183] Case No. U-21297, December 1, 2023, Order, pp. 89, 93.

[184] *Id.* at 93.

[185] *Id.* at 93-94.

[186] Elliott Andahazy Direct, 4 TR 926-7 (noting 253 miles of arc wire will remain after the Company's planned 2026 investment and noting "The Company is continuing to evaluate its plans for the removing the remaining DPLD arc wire….").

[187] Ex A-12 Sch B5.4 p. 13 line 12.

Among other evidence, Company witness Elliott Andahazy discusses the program, identifies alternatives to Hardening presented at the Company's March 2023 Technical Conference, and provides a summary of work performed in this program since 2018.[188] In addition, witness Elliott Andahazy outlined the Company's plans to accelerate Hardening and arc wire removal through 2026.[189] Ms. Elliott Andahazy also presents the Company's assessment of 4.8kV Hardening benefits for circuits treated in 2019 through 2021 with before and 1-year-after assessments across several metrics.[190]

AG-MN witness Stephens opposed the Company's investment plan for 4.8kV Hardening and instead recommended the Company modify its investment to increase DPLD arc wire removal and continue ETTP trimming but halt the other aspects of Hardening.[191] Relying on the Company's 2023 Technical Conference presentation, Mr. Stephens noted that DTE may achieve substantial benefits through sustained vegetation removal (ETTP trimming) plus arc wire removal for substantially less than the cost of hardening. The main other component of Hardening – apart from tree trimming that is wrapped into this program and arc wire removal – is wooden cross arm replacement: every wooden crossarm is replaced with a fiberglass crossarm when a circuit is Hardened, irrespective of its condition.[192] Mr. Stephens recommended the Company proceed in 2025 with arc wire removal at the pace proposed by the Company for hardening in 2025; based on the Company's assessment, the cost would reduce the test year investment to $43.2 million – a 46% reduction in proposed test year hardening spending. For the 2024 bridge, Mr. Stephens recommended the Commission maintain the spending level it approved in U-21297 ($6.7 million

[188] Elliott Andahazy Direct, 4 TR 913-22.

[189] Elliott Andahazy Direct, 4 TR 923-6.

[190] Elliott Andahazy Direct, 4 TR 927-31.

[191] Stephens Direct, 6 TR 3993-8.

[192] Elliott Andahazy Direct, 4 TR 913-4.

for the test year ended 11/30/2024) and reduce bridge year spending by $73.3 million. Finally, Mr. Stephens recommended the Company evaluate and present in the next rate case an assessment of the efficacy of Hardening independent of tree trimming, as well as additional metrics (*e.g.*, dollars per circuit mile for DPLD wire removal) to budget and monitor future DPLD arc wire removal costs.[193]

In rebuttal, witness Elliott Andahazy clarified that Hardening (including tree trimming) does not eliminate wire downs, through an evaluation shows it reduced wire downs 25%.[194] This is no great achievement considering ETTP trimming alone – which is the first step in Hardening - has been shown to achieve significantly greater wire down reductions:[195]

Table 16 – Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	**Difference in % Change in Wire-Down Events ETTP vs. Non-ETTP circuits**
1 Year Post Trim	2,063	-65.5%	-10.1%	**-55.4%**
2 Years Post Trim	1,442	-64.8%	-8.0%	**-56.8%**
3 Years Post Trim	974	-58.3%	-18.5%	**-39.8%**
4 Years Post Trim	491	-52.7%	-37.4%	**-15.3%**

Next in rebuttal, Ms. Elliott Andahazy defends the Company's evaluations of the efficacy of Hardening against Mr. Stephens' criticism that the Company has not evaluated the isolated benefits of non-trimming aspects of Hardening.[196] The rebuttal defends the Company's approach

[193] Stephens Direct, 6 TR 3998; Ex MEC-11.

[194] Elliott Andahazy Rebuttal, 4 TR 1029.

[195] Ex MEC-4 (DTEE Annual Tree Trim Report filed March 1, 2024), p. 11.

[196] Elliott Andahazy Rebuttal, 4 TR 1029-31.

of comparing Hardening to a "do nothing scenario" on the basis that was the methodology in U-20836 and U-21297. This argument is unavailing. As discussed, MNSC has repeatedly criticized the Company's methodology – the failure to isolate non-trimming benefits – in each of those cases. Repeating the same (flawed) methodology in this case does not fix the flaw, it perpetuates it. The "do nothing scenario" is a mythical alternative – the Company is obligated to trim the circuit irrespective of Hardening it. To date, after 3 contested rate cases and 6 years of investment totaling $493.622 million in 4.8kV Hardening,[197] the Company presents no evaluation of the benefits Hardening isolated from tree trimming – *i.e.*, of swapping out wooden cross arms.

The record evidence undermines the Company's evaluation further. As discussed above on the reasonableness of Reliability Model projections on Hardening effectiveness, circuit-level data shows those Hardened in 2020 and 2021 did not result in meaningful reductions in *non*-tree outages in the year of or after treatment, contrary to modeled projection. Interestingly, however, model data show 2020 and 2021 Hardening did have a positive impact (reduction) in *tree*-outages post-treatment, consistent with the premise that tree trimming is driving Hardening benefits:[198]

Circuits Hardened in 2020	Outage Events Non-MED *Tree* Multiple						Circuits Hardened in 2021	Outage Events Non-MED *Tree* Multiple					
	2017	2018	2019	2020	2021	2022		2017	2018	2019	2020	2021	2022
APPOL1142	10	5	4	4	4	2	CHIGO0434	1	0	0	3	0	0
APPOL1318	17	4	0	2	6	3	CHIGO1415	4	1	6	4	1	0
CONAT1269	6	5	7	2	0	6	CHIGO1439	11	10	12	10	1	1
CONAT1293	3	2	6	1	0	2	CHIGO1448	9	5	5	2	2	1
CONAT1310	5	3	6	2	0	0	CHIGO1463	3	5	12	7	3	4
CONAT1362	1	3	6	0	0	0	CHIGO1584	6	6	22	20	2	3
CONAT1446	9	7	3	0	0	0	CHIGO2072	3	3	5	1	0	1
CONAT1447	7	8	10	2	3	16	CHIGO2081	4	1	7	3	4	2
CONAT1450	0	1	3	2	0	0	FLANE1831	1	1	0	1	0	0
CONAT1451	6	3	14	4	0	2	FLANE1835	3	4	6	6	9	0
CONAT2064	19	5	13	3	0	7	FLANE1839	6	7	6	6	2	3

197 Elliott Andahazy Direct, 4 TR 924, Table 3.

198 Ex MEC-72, Ckt Info and Calculations Tab, col BJ (Hardening 2020, 2021), showing columns X to AC (Outage Events / Non-MED / Tree / Multiple / 2017-2022).

CONAT2235	9	8	2	5	1	11
CRTIS1330	3	5	1	2	2	0
CRTIS1332	9	3	0	0	0	0
CRTIS1337	5	12	2	5	2	1
CRTIS1410	3	5	10	3	4	8
CRTIS2031	0	8	7	3	8	11
CRTIS2098	16	9	2	13	3	13
CRTIS2104	4	14	10	5	3	4
HAWTH1853	6	1	1	6	1	0
HAWTH1968	6	4	4	3	2	0
HAWTH2112	8	1	5	2	1	2
TIRMN1102	2	5	2	2	3	3
TIRMN1191	6	2	4	0	0	0
TIRMN1196	2	9	5	0	6	4
TIRMN1223	11	7	6	2	6	1
TIRMN1255	7	9	3	3	0	1
TIRMN1368	11	19	8	7	3	2
TIRMN2093	9	8	3	1	2	5
TIRMN2144	3	5	6	0	4	1
TURNR1000	1	4	0	3	1	0
TURNR1001	6	4	3	0	0	2
TURNR1114	9	8	7	1	3	2
TURNR1143	8	7	2	1	4	7
TURNR1144	6	9	13	5	7	2
TURNR1147	3	8	5	2	0	13
TURNR1148	11	6	4	8	5	9
TURNR1189	6	10	11	5	2	4
TURNR1220	3	7	8	2	3	10
TURNR1477	3	4	7	0	1	3
TURNR2165	10	11	5	3	2	15
AVERAGE	**7**	**6**	**5**	**3**	**2**	**4**

FLANE1840	5	10	3	9	2	4
GARY 1365	2	3	5	3	3	5
GARY 1407	0	2	3	2	1	0
GARY 1431	0	0	0	0	0	0
GARY 1858	2	0	0	0	1	1
GARY 1920	0	0	2	0	1	0
GARY 2115	1	1	6	2	3	8
GRANT0369	0	0	0	0	0	0
GRANT1291	1	3	6	2	0	0
GRANT1306	0	0	2	3	6	3
GRANT1494	1	3	0	4	1	0
GRANT1582	5	1	1	2	0	1
GRANT1598	2	1	6	3	1	3
GRANT2195	9	2	4	4	1	0
GRANT2233	0	3	2	0	0	8
HAWTH0316	0	0	0	0	0	0
HAWTH1176	1	3	7	0	1	2
HAWTH1261	5	1	3	6	0	2
HAWTH1289	12	10	17	9	8	2
HAWTH1301	0	0	0	0	0	0
HAWTH1392	1	2	4	3	0	2
HAWTH1841	4	4	7	2	8	2
HAWTH2020	4	2	7	7	4	0
HAWTH2071	4	2	6	7	4	1
AVERAGE	**3**	**3**	**5**	**4**	**2**	**2**

The rebuttal notes PTMM and tree trimming do not make Hardening redundant – a strawman argument Mr. Stephens never made.[199] Moreover, the rebuttal testimony confirms the points: but-for the Company's approach of excluding Hardened circuits from PTMM, PTMM would serve to identify and replace *defective* cross arms. The Company has shown no benefit only cost from replacing *non*-defective cross arms. But-for the Company's approach of starting Hardening with comprehensive circuit trimming then putting the circuit onto the ETTP cycle,

[199] Elliott Andahazy Rebuttal, 4 TR 1032.

ETTP trimming would serve the same purpose at a fraction of the cost. The point is not that PTMM and trimming are redundant to Hardening, it is that (a) the Company uses Hardening as a (more costly) alternative to PTMM and trimming,[200] (b) the benefits of trimming are not properly attributable to Hardening.

Next, witness Elliott Andahazy presented in rebuttal an updated analysis comparing reliability on circuits Hardening and in a control group for 3 years of before and after Hardening.[201] But the updated analysis makes no attempt to fix the methodological problem – the inclusion of trimming benefits in Hardened circuits and the exclusion of trimmed circuits in the control group.[202] The circuits in the Hardened group had not been trimmed per-Hardening for an average of 8 years;[203] the circuits in the control group hadn't been trimmed in 6 years.[204] The analysis thus double-distorts the benefits of Hardening: first, it show benefits of trim+Harden on circuits after overdue trimming – thus increasing treatment benefits on Hardened circuits; and it compares them to reliability on untrimmed circuits also overdue for trimming – thus likely performing worse that average. The analysis is not redemptive of Hardening. What the evaluation is still lacking is removing the benefits of trimming from Hardened circuits. Reliability Model data show the year of and after Hardening result in no real improvement in *non*-tree outages but notable and immediate tree outage reductions, suggesting trimming drives Hardening benefits:[205]

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[200] See Exs MEC-42, 43 (DTE puts circuits hardened on the PTMM and ETTP cycle after hardening).

[201] Elliott Andahazy Rebuttal, 4 TR 1033-5, Tables 1, 2, 3.

[202] Ex MEC-46.

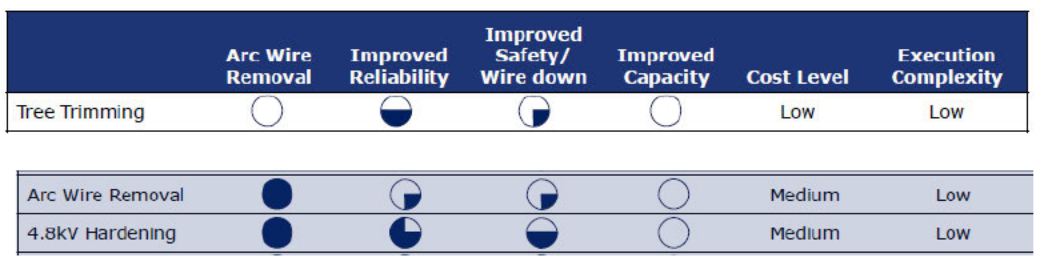
[203] Ex MEC-47, p. 2.

[204] Ex MEC-47, p. 1.

[205] Ex MEC-72, Ckt Info and Calculations Tab, col BJ (Hardening 2020, 2021), showing columns L to Q (Outage Events / Non-MED / Non-Tree / Multiple / 2017-2022) and X to AC (Outage Events / Non-MED / Tree / Multiple / 2017-2022).

Hardened	Multiple Outage Events	2017	2018	2019	2020	2021	2022
2020	Non-Tree	4	7	4	18	5	4
	Tree	7	6	5	3	2	4
2021	Non-Tree	5	4	4	4	13	9
	Tree	3	3	5	4	2	2

The rebuttal next asserts that proceeding with DPLD apart from Hardening would not provide nearly all the benefits.[206] The rebuttal replicates the chart from the Technical Conference – also replicated in direct testimony – comparing DPLD, Hardening, Pre-Conversion, Conversion, and Microgrids.[207] The testimony notes Hardening provides benefits besides arc wire removal. One flaw in the argument is that the recommendation is to proceed with ETTP *and* arc wire removal; DTE's Technical Conference assessment shows their equal Hardening:[208]


	Arc Wire Removal	Improved Reliability	Improved Safety/ Wire down	Improved Capacity	Cost Level	Execution Complexity
Tree Trimming					Low	Low
Arc Wire Removal					Medium	Low
4.8kV Hardening					Medium	Low

Moreover, the Company's assessment of the benefits of arc wire removal lacks foundation. In discovery inquiring into the potential benefits of arc wire removal, the Company said: "The work scope of only removing arc wire is approximately half of the 4.8kV Hardening Program. Therefore, the Company expects approximately half of the benefits seen from the 4.8kV Hardening Program."[209] It seems the Company gave lip service and little more to the concept of proceeding with arc wire removal independent of Hardening. The Commission was clear in U-21297 that arc wire removal is the key benefit of Hardening, and it is proceeding too slowly. Mr. Stephens'

[206] Elliott Andahazy Rebuttal, 4 TR1036-1037.

[207] *Id.*; *see also* Elliott Andahazy Direct, 4 TR 1039; Ex A-23 Sch M12 p. 39.

[208] Excerpted from Ex A-23 Sch M12, p. 30.

[209] Ex MEC-50, p. 2.

recommendation to proceed with arc wire removal – while getting 4.8kV circuits on the ETTP cycle – is a more cost-effective way to remove arc wire than Hardening.

The rebuttal next notes that Hardening investments would not render equipment redundant when the lines are converted.[210] According to the testimony, Hardened circuits are deprioritized for conversion, and the new equipment is configured for 13.2kV. But even if the new equipment can still be used when the circuit is eventually converted, there is cost redundancy because the cost of equipment is not the full cost of Hardening – some of the Hardening cost is the labor. Hardening then Conversion is undoubtedly more costly than just Conversion. The Company never assessed the benefits, costs, and value of DPLD arc wire removal plus trimming followed by eventual Conversion.[211]

Next, the rebuttal opposes doing a benefit-cost analysis to evaluate the benefits of the non-DPLD and non-trimming components of Hardening on the basis the program is "mature," and the evaluation would delay the program.[212] The argument that a BCA would delay anything is unsupported. The Company has ample historical data about each circuit to assess the reliability benefits of non-tree components of Hardening, there is no reason an evaluation would be difficult or slow.

Moreover, the Company position makes the case for the Commission to slow the roll out of new distribution strategic capital programs. Since U-20836, MNSC has been advocating to pause or slow spending and first evaluate benefits and cost-effectiveness of 4.8kV Hardening. The Company filed Case No. U-21297 before the Technical Conference and it proposed to end Hardening, but then unilaterally decided to ramp it back up. It invested nearly $500 million without

[210] Elliott Andahazy Rebuttal, 4 TR 1037-9.

[211] Ex MEC-52 (no analysis of relative Conversion costs with and without Hardening).

[212] Elliott Andahazy Rebuttal, 4 TR 1040-1.

providing a proper BCA. However "mature" the program, the Company must support its investments, and it has not done so. Mr. Stephens' recommendation for a BCA before the Company proceeds with another $240.690 million for 4.8kV Hardening in 2024, 2025, and 2026, is prudent, irrespective of program maturity.[213] Alternatively, the Commission should adopt Mr. Stephens' recommendation to approve half the spending for DPLD arc wire removal alone.

Finally, the rebuttal argues its decision to ramp up Hardening spending after ramping it down in U-21297 is warranted by the Commission's directive that "the removal of the arc wire should be going faster."[214] It continues that 2024 spending already underway and the work and investment cannot be undone, and shifting work in 2025 to DPLD removal only would cause delays. These concerns offer no legitimate opposition to Mr. Stephens' recommendation. First, the Commission approved only the Company's proposed 2024 spending in U-21297. And the Commission never supported increased spending on Hardening – it supported faster DPLD removal. The Company took a risk when it interpreted the Commission's support for faster DPLD removal to mean it should increase Hardening spending and spend accordingly in 2024. The risks emanating from the projected test year and timing of rate cases should remain squarely on the utility, not ratepayers. Second, the Company has ample time to shift course in 2025 to shift the investment to remove DPLD wire only.[215]

The Commission should not condone DTE's foot-dragging and pivoting by approving its 2024 and 2025 4.8kV Hardening investments. The Company has already spent nearly half a billion dollars in distribution capital investment to harden 1,492 miles.[216] Of that investment, $18.775

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[213] Elliott Andahazy Direct, 4 TR 926 (2024-2026 spending plan).

[214] Elliott Andahazy Rebuttal, 4 TR 1042-3 (quoting Order in U-21297).

[215] Ex MEC-53 ("Approximately 6 months to complete construction in progress, and to review and update design packages for circuits where construction has not started.").

[216] Elliott Andahazy Direct, 4 TR 924, Table 3.

million was to trim trees.[217] The Company might have achieved much of the reliability benefits from the trimming alone. Instead of approving the Company's 2024 and 2025 proposed Hardening investments, the Commission should approve the recommended disallowance of $73.333 million in 2024 and $81.800 million in 2025 to facilitate the shift to DPLD arc wire removal.

ii. Pole and Pole Top Maintenance and Modernization (PTMM)[218]

In U-20836, the ALJ found DTE failed to explain why PTMM spending was increasing while the standards were unchanged.[219] The Commission agreed, finding DTE failed to explain or justify its requested significant PTMM investment increases and capping test year spending at $33.44 million.[220] In U-21297, the ALJ found DTE failed to explain why it overspent by double the spend level approved in U-20836 and failed again to explain the basis for projected cost increases.[221] And the Commission again agreed:[222]

> The company ignored the directives in the November 18 order including the cap on spending and once again failed to establish the basis for these significant cost increases. While the Commission does not always find that historical spending provides a basis for determining future spending (particularly where the utility's strategy has changed), the Commission accepts MNSC's proposed adjustment and cap of $63.45 million in this case as the most reasonable choice on this record, especially since the deviation from historical amounts is so great and the program has not been shown to be cost effective. 6 Tr 3550-3554. The Commission also approves the

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[217] Ex MEC-4, p. 7.

[218] MNSC believes the record on this issue is the following:

- Direct Testimony of DTE witness Morgan Elliott Andahazy, 4 TR 932-59; Rebuttal Testimony of M. Elliott Andahazy, 4 TR 1044-57; and Cross Examination of Ms. Elliott Andahazy, 4 TR 1067-1109;
- Ex A-23 Schs M5, M8, M9, M10, M13; A-51, Schs PP10-PP14;
- Direct Testimony of AG, MEC & NRDC witness Dennis Stephens, 6 TR 4008-15;
- Exs MEC-4, 11, 13, 14, 15, 40, 55, 56, 57, 72, 75;
- Direct Testimony of ABATE witness James R. Dauphinais, 6 TR 3380-82.

[219] Case No. U-20836, Nov. 18, 2022, Order, p. 98.

[220] Case No. U-20836, Nov. 18, 2022, Order, p. 98.

[221] Case No. U-21297, Dec. 1, 2023, Order, p. 95.

[222] *Id.* at p. 96.

> reporting requirements (agreed to by the company) detailed by MNSC's witness. This will include reporting annual metrics with respect to pole and pole top inspections and testing, similar to the annual tree trimming reporting. See, 6 Tr 3559-3560.

DTE filed this case before filing the annual PTMM report, indicating "the data for the required report was being prepare" at the time testimony was being prepared.[223] Notwithstanding the lack of a report, DTE proposes to double PTMM spending in 2025 and more in the IRM years:[224]

2022	2023	2024	Test Year 2025	IRM Year 2026	IRM Year 2027
$83.934 million	$79.075 million	$63.450 million	$121.000 million	$150.000 million	$200.000 million

Witness Elliott Andahazy supports the Company's PTMM investment plan.[225] Consistent with the testimony in U-20836 and U-21297, the direct testimony discusses the scope of the program and its evolution since 2019, when "Modernization" was added.[226] In 2019, the Company updated its pole and pole-top inspection and construction specifications per benchmarking.[227] Seemingly a driver of increasing costs, the Pole Top Maintenance Specification defines some pole top equipment to be "defective" thus requiring replacement irrespective of condition – porcelain cutouts, automatic sleeves, blackburn hot tops, and porcelain post insulators.[228] Inspection and replacement standards are substantively unchanged since 2019, but the PTMM program has since evolved in two ways: (a) starting in 2021, discontinued Joint Use Inspections – inspecting co-

[223] Elliott Andahazy Direct, 4 TR 947.

[224] Ex A-12 Sch B5.4, p. 13 line 13; Ex A-33 Sch X1.

[225] Elliott Andahazy Direct, 4 TR 932-60.

[226] Elliott Andahazy Direct, 4 TR 933-53.

[227] Elliott Andahazy Direct, 4 TR 936-41, 948; Ex A-23 Sch M9 (pole specification); Elliott Andahazy Cross, 4 TR 1083-6 (discussing 2019 pole standards and subsequent modifications, which were non-substantive).

[228] Ex A-23 Sch M10, pp. 5, 8, 9, 16.

locating pole equipment; and (b) starting in 2023, inspection quality control and inspection process improvements.[229] Starting in 2022, pole and pole-top "defects" per mile increased,[230] pole and pole-top replacements soared,[231] but PTMM circuit miles remained steady. Witness Elliott Andahazy also addressed PTMM circuit prioritization.[232] She also sponsored a Benefit Cost Analysis (BCA) report developed by the 1898 Company to support the PTMM program.[233]

AG-MN witness Stephens opposed the Company's PTMM investment plan.[234] He recommended the Commission cap 2025 spending at the level approved in U-21297 ($63.45 million), in effect disallowing $57.550 million, and rejecting the proposed IRM investment in PTMM.[235] He addressed the cost implications of DTE's decision to modify its pole and pole top inspection cadence and standards, noting that such substantive programmatic decisions necessarily result in cost increases and thus warrant thorough pre-assessment of costs and benefits.[236] He noted the lack of evidence that DTE management reviewed and approved the standards modifications or the cost implications of them before they were implemented.[237] Only after modifying the standards, the Company obtained the BCA, which Mr. Stephens found flawed, overestimating the benefits of PTMM.[238] Because DTE has not yet shown the benefits of PTMM on circuits that DTE treated, it has not supported its proposal to increase PTMM spending.[239]

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[229] Elliott Andahazy Direct, 4 TR 948-9; Elliott Andahazy Cross, 4 TR 1083-5.

[230] Elliott Andahazy Direct, 4 TR 951.

[231] Elliott Andahazy Direct, 4 TR 952.

[232]Elliott Andahazy Direct, 4 TR 954-7, Table 11, Figure 14.

[233] Elliott Andahazy Direct, 4 TR 947-8, 958-959; Ex A-23 Sch M13 (PTMM Benefit Cost Analysis Whitepaper).

[234] Stephens Direct, 6 TR 4008-15.

[235] Stephens Direct, 6 TR 4015, 4029; Ex MEC-11.

[236] Stephens Direct, 6 TR 4008-11.

[237] Stephens Direct, 6 TR 4010-1; Ex MEC-14.

[238] Stephens Direct, 6 TR 4011-3.

[239] Stephens Direct, 6 TR 4014.

In rebuttal, witness Elliott Andahazy defends the Company's aspirational inspection cycle (10 year for poles, 5 years to pole tops), noting it is in line with utilities in nearby states.[240] While potentially laudable, PTMM is having the ironic effect of significantly *slowing* the pole and pole top inspection cycle, not progressing DTE towards its aspiration cycles. Increasing PTMM condemnation rates led to a construction backlog of pole and pole top replacements, so DTE halted most inspections in 2023.[241] This supports pausing PTMM spending increases to catch up. Moreover, since its 2018 benchmarking, DTE has indicated a shorter pole top inspection cycle is warranted, yet DTE has no plan to get there. It should pause spending while it develops a reasonable plan to transition to an inspection cycle in line with its aspirational goals and benchmarking. Inspections are non-capital and a small fraction of PTMM costs (3-4% in 2022, 2024, and 2025).[242] Given their low cost and high value, DTE should prioritize regular inspections notwithstanding the backlog of replacements. DTE should also consider bifurcating PTMM so mandatory inspections progress towards the shorter cycle, while preemptive replacements may be delayed, reprioritized, or coordinated with other circuit investments.

Witness Elliott Andahazy also defends the Company's decisions updating pole and pole top construction specifications without analysis of incremental benefits and costs to ensure cost-effectiveness.[243] The rebuttal notes documents were provided in discovery, which – while incomplete – show three internal analyses of modified pole standards pre-enactment. The 2015 *Wood Poles Class Upgrade Overview* presented to EE Leadership in 2015 showed upgrading to Class 3 and eliminating Class 4 and 5 poles would add $420,000 annually.[244] The 2016

[240] Elliott Andahazy Rebuttal, 4 TR 1045; see also Elliott Andahazy Direct, 4 TR 938.

[241] Elliott Andahazy Direct, 4 TR 952-953, Table 13; Elliott Andahazy Cross, 4 TR 1071; Ex A-12 Sch B5.4.8 line 9.

[242] Ex A-12 Sch B5.4.8 line 9.

[243] Elliott Andahazy Rebuttal, 4 TR 1045-6.

[244] Ex A-23 Sch PP13, p. 8.

Engineering -OEP Report concluded that upgrading to Class 3 poles and Grade B construction standards would increase overall pole costs (material and labor) by $2,713,000 annually.[245] The 2018 *Wood Pole inspection/reinforcement/replacement overview* would move DTE "to a best in class model that lowers risk" and increase equipment replacement, but identified no cost estimate and discussed no benefits.[246] None of the presentations relate to the pole top specifications imposing preemptive replacement irrespective of equipment condition, which drive costs.[247] None show the Company assessed costs, customer benefits, or cost-effectiveness before revising the pole and pole top specifications.

The remainder of the rebuttal defends against criticisms of the 1898 Company BCA.[248] While there are others, the main flaw in the BCA is the assumed benefits of PTMM in reducing outages are unverified projections of equipment failure based solely on equipment age. There are various ways DTE could assess pole and pole top replacement reliability benefits. Mr. Stephens testified DTE could track historic failure rates of the subject equipment (poles, porcelain insulators and cutouts, arrestors), but it does not.[249] He testified DTE could capture data about the cause of equipment-classified outages, but it does not.[250] DTE could evaluate outage events before and after replacing poles and pole top equipment (like it evaluates Hardening and ETTP), but it has not.[251] DTE could evaluate outage events on circuits post-PTMM to outage events on a control group of circuits (like it evaluates ETTP), but it has not.[252] The Commission in U-21297 ordered DTE to

245 Ex A-23 Sch PP13, p. 3.

246 Ex A-23 Sch PP13, p. 13.

247 Ex A-12 Sch B5.4.8 line 11.

248 Elliott Andahazy Rebuttal, 4 TR 1046-57.

249 Stephens Direct, 6 TR 4012; Ex MEC-15.

250 Stephens Direct, 6 TR 3991.

251 Elliott Andahazy Cross, 4 TR 1091-2, 1108-9.

252 *Id.*; Exs MEC-55, 57.

report annual PTMM metrics "similar to the annual tree trimming reporting," indicating the Commission expects an effectiveness assessment with reliability metrics before and after PTMM and PTMM compared to a control group.[253] DTE plans to do so starting in 2025.[254] Meanwhile, DTE wasted no time hiring 1898 Company to develop the BCA using generalized equipment assumptions by early March 2024 to support its latest PTMM ramp up request.[255]

The BCA does not substitute for an evaluation of the actual reliability benefits of PTMM. The BCA projects future reliability benefits post-PTMM based on a proprietary national database of failure probability forecasts for Poles and Pole Tops based on equipment age.[256] It compiles outages after PTMM and compares it to outage interruptions under a Do Nothing Scenario based on its propriety equipment failure survival probability curves.[257] It projects 40 years of future circuit performance and customer interruptions – from 2024 to 2063 – based on assumptions based on equipment age, not on historic demonstrated and measured reliability reductions based on equipment condition.[258] The BCA assumptions are unvalidated and unverified projections of future outage reductions from PTMM.

Since 2019, DTE has been replacing poles and pole top equipment consistent with the 2019 specifications. In 2021, for example, DTE replaced 1,061 "defective" poles and "defective" equipment at 3,236 pole top locations in 2021 at a cost of $31.647 million.[259] That investment should have produced measurable reliability benefits. Between 2019 and 2023, under the same

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[253] Exs MEC-4, 70 (DTE Annual Tree Trim Reports).

[254] Ex MEC-40 ("The Company expects to begin performing this analysis for its new annual PTMM report starting in 2025.").

[255] Ex A-23 Sch M13.

[256] Ex A-23 Sch M13 p. 14; Elliott Andahazy Direct, 4 TR 976; Elliott Andahazy Cross, 4 TR 1109.

[257] Ex A-51 Sch PP10 (NDA BCA Model); Elliott Andahazy Cross, 4 TR 1109.

[258] Ex MEC-56.

[259] Elliott Andahazy Direct, 4 TR 952.

specifications, DTE replaced 12,131 poles, reinforced 4,119 poles, and replaced 21,384 pole top locations – a ratepayer investment of $254.857 million.[260] DTE took the position that PTMM evolved with "enhanced specs" in 2023, so pre-2023 PTMM is not representative of post-2023 PTMM benefits.[261] But 2023 PTMM changes address inspection quality not replacement, and there were no inspections in 2023.[262] There is no evidence replacement specifications or implementation changed substantively post-2019 enactment to mean pre-2023 replacements are materially different than post-2023 replacements. It is inexcusable that DTE has never assessed or presented reliability benefits resulting from ratepayers' investment of over $250 million in PTMM.

Another flaw in the 1898 Company BCA is that it compares PTMM to a "Do Nothing Scenario," which is unreasonable. The BCA assumes there will be no visual pole inspection, no pole top maintenance, no physical inspections, no treatment of any kind – it runs all poles and pole equipment to failure.[263] DTE has a regulatory compliance obligation to inspect poles every 10-12 years.[264] The ETTP program aims to trim each circuit every 5 years at least. The Do Nothing Scenario is not a regulatorily compliant scenario, making it unreasonable. The alternative to PTMM is not 40-years of non-maintenance but instead regular inspections and maintenance based on equipment condition. PTMM preemptively replaces functional but obsolete equipment that has never been demonstrated to be at risk of failure or causing outages.

Even if the 1898 Company BCA were flawless, its results are revealing. The analysis compares the cost to treat a circuit with PTMM in 2024 to (a) avoided reactive costs to respond and repair outages from 2024 to 2063 in the Do Nothing Scenario, and (b) the cost to customers

[260] Elliott Andahazy Direct, 4 TR 952, Table 10; Ex MEC-40.

[261] Kryscynski Cross, 3 TR 569; Ex MEC-72, Reliability Model, Benefits Walkdown & Degradation Tab.

[262] Elliott Andahazy Direct, 4 TR 948-9, 952-3.

[263] Elliott Andahazy Cross, 4 TR 1101-2.

[264] Kryscynski Cross, 4 TR 526; Elliott Andahazy Direct, 4 TR 946.

resulting from outages from 2024 to 2063 in the Do Nothing Scenario using the LBNL ICE calculator.[265] Of the nearly 3,800 circuits in the BCA, PTMM was cost effective for only about 100 circuits in terms of avoided reactive costs (ratio >1), or less than 3% of circuits.[266] System-wide, PTMM is not cost-effective relative to avoided reactive costs.[267] Per the BCA, PTMM is not a cost effective program based on benefits to the Company and ratepayers generally; it only becomes cost-effective for some circuits when customer avoided customer outage costs through 2063 are included. Even if the BCA were acceptable despite its flaws, it would be premature to rely on it to approve future PTMM spending without regulatory guarantee customers will receive the identified benefits – *i.e.*, avoided outage costs. Stated differently, if customer avoided costs justify Company spending on an otherwise cost-ineffective program, then DTE must be accountable to customers for those benefits. Customers should be on both sides of the equation. To date, there has been little evaluation of the efficacy of past distribution strategic capital spending let alone regulatory consequence where the utility failed to demonstrate credible benefits. The Commission should not condone using a BCA to justify spending that assesses cost effectiveness based on customer avoided costs without mechanisms to hold the Company accountable for achieving the customers benefits. [268]

It is premature to increase the PTMM investment in the test year and IRM years as the Company requests. DTE has not yet provided the first report ordered by the Commission in U-21297. The BCA is not a credible alternative because it is based on unverifiable generalized

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[265] Elliott Andahazy Direct, 4 TR 947.

[266] Ex A-51 PP10 (NDA BCA model), Summary Tab, Col J BCA (Emergent Replacement Risk only); Elliott Andahazy Cross, 4 TR 1105-1106.

[267] Elliott Andahazy Cross, 4 TR 1104-5.

[268] For example, a PBR mechanism or a regulatory asset where return on the investment is contingent on demonstrated benefits.

projections of future outage benefits untethered to any evaluation of actual performance of circuits after PTMM. Increasing the PTMM investment is also premature before the distribution audit is fully assessed. It is also premature before ETTP is 100% on-cycle and the full extent of ETTP reliability benefits may be assessed. It is premature because DTE has not shown that upgrading poles and replacing porcelain cutouts, automatic sleeves, blackburn hot tops, and porcelain post insulators has been cost-effective for ratepayers. Moreover, it is also dubious the preemptive replacement of poles and pole-top equipment targeted by PTMM reduces outages, customer interruptions, and customer minutes interrupted to the material degree DTE projects because equipment is not the major driver of outages, particularly during weather events. The Commission should adopt Mr. Stephens' recommendation to hold PTMM spending at 2023 levels in the test year and reject all PTMM spending in the IRM.

iii. Breaker and URD Replacement Programs in the IRM [269]

DTE proposes to include $15 million annually in its extended 2026 and 2027 IRM proposal for Breaker Replacement and $15 million and $20 million respectively in 2026 and 2027 IRM years for URD Replacement.[270] AG-MN witness Stephens opposed both proposals.[271] He found neither program delivers benefits in excess of customer costs and noted the inherent challenges with rider programs shifting risk to ratepayers. Moreover, Mr. Stephens noted the Commission in U-21297, in approving 90% of spending for each program, requested more evidence to show these

[269] MNSC believes the record on the issues is as follows:
- Direct Testimony of DTE witness Morgan Elliott Andahazy Direct, 4 TR 997-1010; Rebuttal Testimony of Ms. Elliott Andahazy, 4 TR 1057-64;
- Ex A-23 Sch M8; Ex A-33 Sch XI; Ex A-23 M13;
- Direct Testimony of AG, MEC & NRDC witness Dennis Stephens, 6 TR 4026-28;
- Exs MEC-11, 68, 73.

[270] Ex A-33, Sch X1.

[271] Stephens Direct, 6 TR 4026-4028; Ex MEC-11.

program investments actually contribute to reduced outage frequency and duration.[272] DTE has not yet provided any assessment of outage reduction benefits.

Company witness Elliott Andahazy filed testimony in rebuttal.[273] She acknowledged the Company has not provided an evaluation of cost-effectiveness for these programs.[274] The rebuttal references the BCAs for PTMM and Strategic Undergrounding (the 1898 Company BCA) as part of the Company's strategy to support future investments, but that is not what the Commission requested in U-21297. As discussed above related to the 1898 Company BCA for PTMM, that assessment provided a forward projection of future costs and benefits of the program based on generalized assumptions related to equipment age – not an evaluation whether DTE's investment has contributed to outage reductions. The Company would waste resource if it were to simply replicate the 1898 Company BCA methodology for additional distribution strategic capital programs like Breaker and URD Replacement in future cases – unless accompanied by validation supported by actual historic data to support benefits projections for these programs.

The rebuttal also notes these programs are essential so a "run-to-failure approach is simply not acceptable."[275] Mr. Stephens never suggested run-to-failure, he reiterated a need to assess cost-effectiveness to support future IRM-year investments in these programs.

The rebuttal also reiterates historic program investments level and asserts breakers and URD cable are beyond their expected 40-year useful life and on a slow replacement cycles.[276] This is also non-responsive to Mr. Stephens' testimony and does not indicate whether or how breaker or cable *age* correlates to outage risk. That some breakers and URD cables are beyond their useful

[272] Case No. U-21297, December 1, 2023, Order, pp. 99-101.

[273] Elliott Andahazy Rebuttal, 4 TR 1057-64.

[274] *Id.* at 1058-9, 1062.

[275] *Id.* at 1059, 1062.

[276] *Id.* at 1059-60, 1063-4.

life does not support approval for IRM-year replacement investments. There is no evidence of poor breaker or URD cable condition or correlation between breaker/URD cable age and historic outages. The Company has yet not satisfied the Commission's directive in U-21297 to demonstrate cost-effectiveness, so it is particularly premature and inappropriate to include preemptive breaker and URD cable replacement in the 2026 and 2027 IRM proposal.

The Company has not met its burden to demonstrate that it is reasonable and prudent to include $30 million in the proposed 2026 IRM and $35 million in the proposed 2027 IRM for Breaker and URD Replacements.

4. Infrastructure Redesign and Modernization

i. Subtransmission Redesign and Rebuild [277]

DTE witness Satvir Deol supports the Company's projected capital expenditures for the Subtransmission Redesign and Rebuild Program. He describes Subtransmission as system that "transmits higher transmission voltage across the service territory to stations that step down the voltage to distribution levels to serve customers."[278] DTE seeks to include in rate base $112.5 million of capital expenditures on Subtransmission in 2024 and $43.6 million in 2025.[279] The Company also projects $53.8 million in Subtransmission spending in 2025 under the IRM, which

[277] MNSC believe the following portions of the record address Subtransmission Redesign and Rebuild:

- Revised Direct Testimony of DTE witness Satvir S. Deol, 5 TR 1176-1191; Rebuttal Testimony of Mr. Deol, 5 TR 1240-1255 and 1262-3; Cross Examination of Mr. Deol, 5 TR 1328-1361;
- Ex A-12, Sch B5.4, pp. 14-16;
- Direct Testimony of AG, MEC & NRDC witness Dennis Stephens, 6 TR 4015-21; Confidential Direct Testimony of Mr. Stephens, 6 TR 5296-5303;
- Ex MEC-11, 15, 16, 17, 18, 82, 83, 84, 85, 86, 88, 90, 104, 111, and 119.

[278] Deol Direct, 5 TR 1176.

[279] Ex A-12 Sch B5.4, p. 16, line 114.

the Commission approved in Case No. U-21297.[280] DTE also requests pre-approval under the IRM of $55 million for Subtransmission in 2026 and $65 million in 2027.[281]

In Table 8 of this direct testimony, Mr. Deol presented the Subtransmission projects included in this case, with a summary of the drivers for each.[282] Capacity is the most commonly listed driver, and is either described qualitatively or with specific references to a percentage of loading.[283] Mr. Deol originally testified that about one-third of the subtransmission circuits violate DTE's planning criteria, but changed that to one-third of circuit miles on the stand.[284] (More on the planning criteria and the claimed violations below.)

AG-MN witness Dennis Stephens testified that Subtransmission projects are quite costly – both on a per project level and in terms of total planned spending.[285] Based on the evidence, Mr. Stephens concluded that DTE has not demonstrated the reasonableness, prudence, or necessity of the amount of Subtransmission spending included in this case. He also testified that, similar to Conversions projects discussed below, DTE's exhibits for Subtransmission projects are not transparent, with spending over multiple years that makes it difficult to determine their full cost or ascertain their value to customers.[286] Additionally, cross exam of Mr. Deol showed that the loading data he referred to in his testimony does not support – and even contradicts – his claims about capacity.

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[280] Foley Direct, 2 TR 119, Table 1; Case No. U-21297, December 1, 2023, Order, p. 291.

[281] Foley Direct, 2 TR 119, Table 1.

[282] Deol Direct, 5 TR 1187-89.

[283] *Id.*

[284] Deol Direct, 5 TR 1181.

[285] Stephens Direct, 6 TR 4017; specific figures at Stephens Confidential Direct, 6 TR 5298.

[286] Stephens Direct, 6 TR 4017.

a. <u>Outages do not justify such a large Subtransmission investment.</u>

First, Mr. Stephens explained that the Subtransmission system is not currently a significant cause of outages or customer interruptions. Only 26% of subtransmission equipment outages in recent years resulted in an interruption in service; and the subtransmission system caused just 3.9% of all DTE customer minutes interrupted from 2019-2023.[287] Because subtransmission service interruptions are such a small proportion of DTE's total service interruptions, they do not justify large annual capital spending program for reliability.[288] Instead, the merits of each project should be evaluated individually, and in a way that reflects the limited risk reductions available through the already-redundant design of DTE's system.

b. <u>DTE exaggerates the resilience benefit of the Subtransmission program.</u>

Second, while Mr. Deol testified that the Subtransmission Redesign and Rebuild program improves resilience, Mr. Stephens explained that it only does so indirectly.[289] DTE rebuilds circuits with larger conductor and steel poles, which are less susceptible to storm damage.[290] While that is good so far as it goes, it is not a justification for such expensive projects. Wind and ice comprised just 1.3% of subtransmission equipment outages from 2019 to 2023.[291] In rebuttal, Mr. Deol argued that trees and one-quarter of equipment failure cause codes should also be included in storm damage – which would increase the percentage of subtransmission outages related to storms.[292] However, he failed to explain why tree trimming is not a more cost-effective strategy for tree-

[287] Stephens Direct, 6 TR 4016, based on data reported in Ex MEC-15 and MEC-16.

[288] Stephens Direct, 6 TR 4016.

[289] *Id*. at 4017.

[290] *Id*.

[291] Stephens Direct, 6 TR 4017; Ex MEC-16.

[292] Deol Rebuttal, 5 TR 1251-1252.

related subtransmission outages than replacing and upgrading entire subtransmission circuits. And he provided no support whatsoever for his assumption that one-quarter of equipment failures should be considered storm-caused.

c. DTE's planning criteria exaggerates the need for full redundancy on the Subtransmission system.

Mr. Deol testified that DTE analyzes the condition of the Subtransmission system annually to determine whether it meets the Company's "planning criteria."[293] Failing to meet DTE's planning criteria is not the same as being overloaded. Rather, DTE uses a single contingency criteria that requires full redundancy – where each subtransmission circuit must have enough extra capacity to carry all of the load of any subtransmission circuit adjacent to it during peak loading.[294]

Mr. Deol described single contingency as "standard industry planning"[295] – though he provided no industry reference to support this claim. When asked in discovery to provide a source, he declined and instead simply claimed that single contingency planning "is considered necessary and part of good engineering practice when it comes to feeding substations that serve a large number of customers."[296]

Mr. Stephens testified that DTE exaggerates the need for full redundancy on the subtransmission system at all times of the year. Mr. Stephens said that in his experience, the vast majority of distribution substations have a back-up source of subtransmission supply for at least most of the hours of the year.[297] (Mr. Stephens had to rely on his experience because DTE refused to provide a list of which distribution subs have backup supply.)

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[293] Deol Direct, 5 TR 1177-1178.

[294] *Id*. at 1178-79.

[295] *Id*. at 1178.

[296] Ex MEC-82 (discovery response MNSCDE-17.6).

[297] Stephens Direct, 6 TR 4018.

Mr. Stephens noted that a cost-benefit evaluation must be done to determine whether an expensive upgrade is really necessary when back-up capacity is adequate for 97% of the hours in a year (for example), to cover the other 3% of hours.[298] But DTE does no benefit-cost analysis on proposed Subtransmission projects, let alone any analyses that monetize risk reduction value in dollars.[299]

In rebuttal, DTE witness Deol emphasized the importance of "greater design margins and redundancy" in the subtransmission system because of the potentially large impact of an outage in that system on customers.[300] That is also fine so far as it goes, but does not answer the key questions raised by Mr. Stephens about how much design margin is necessary, what is the relative reliability gain these projects are producing, and what is the cost to customers. Because DTE refuses to even acknowledge these questions – let alone answer them – the Company has not demonstrated that its use of a uniform single contingency planning criteria requiring full redundancy at peak load for all subtransmission equipment is reasonable.

This issue also came up in DTE's last rate case, U-21297. MNSC entered Mr. Deol's testimony from that case as Exhibit MEC-119 in this case. In U-21297, MNSC noted (and notes again) that the only reference DTE can come up with to support its criteria is the USDA Rural Utilities planning document that was admitted in this case as Exhibit MEC-104.[301] However, DTE does not rely on this document in distribution system planning.[302] Rather, someone on Mr. Deol's team found it while looking for an industry source to support his rebuttal in the prior case.[303]

[298] *Id*.

[299] Stephens Direct, 6 TR 4019; Ex MEC-18 (discovery responses MNSCDE 5.4a-c).

[300] Deol Rebuttal, 5 TR 1242.

[301] Ex MEC-104, 2017 – USDA Rural Utilities Service Electric System Long-Range Planning, RUS Bulletin 1724D-01A.

[302] Ex MEC-119, Deol Cross in U-21297, 2 TR 328.

[303] *Id*.

Further, the document is not written for a large metropolitan utility like DTE – it is written for rural electric cooperatives.[304] Most importantly, the section of the USDA bulletin DTE cites in Mr. Deol's rebuttal does not in fact establish single contingency as the standard planning criteria in the electric industry. Rather, the USDA bulletin says that planning criteria should be established and that several factors should be considered in doing so – including "load shifts during emergency situations," but also including lots of other things, too.[305]

The PFD in U-21297 described these concerns in detail, and ultimately found that "DTE has failed to support the reasonableness and prudence of the program, the individual projects, or the pace of spending on this program."[306] The PFD emphasized that "[m]ost significantly, Mr. Stephens expert opinion is credible that DTE's planning criteria require additional justification, which DTE did not provide…"[307] The Commission – while adopting the PFD's approval of limited bridge and test year amounts – also adopted the PFD's findings.[308]

Mr. Deol also emphasized the need for redundancy to provide operational flexibility for DTE to shut down equipment in order to perform routine maintenance activities.[309] Again, however, DTE fails to show that this issue is more than theoretical. MNSC asked repeatedly for incidents in which customers were actually out of service during an intentional shutdown of subtransmission equipment, and DTE refused to identify any.[310]

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[304] Deol Cross, 2 TR 328; see also Ex MEC-80, the USDA bulletin, which uses the word "cooperative" 70 times.

[305] Ex MEC-104, USDA bulletin, pp. 15-16.

[306] Case No. U-21297, October 5, 2023, PFD, p. 275.

[307] Case No. U-21297, October 5, 2023, PFD, p. 275.

[308] *Id*. at 106.

[309] Deol Rebuttal, 5 TR 1243.

[310] Ex MEC-83, discovery responses MNSCDE-19.5a-b; Ex MEC-84 (discovery responses MNSCDE-19.6).

d. DTE provided only limited loading data, and what it did provide contradicted the Company's claims.

Next, Mr. Deol reiterated his direct testimony that DTE models the subtransmission system annually, and the model results show "that one-third of the circuits on the subtransmission system has a thermal and/or a voltage planning criteria violation."[311] He stated that a "sample of this data was provided in discovery response U-21534 MNSCDE-20 5.5a(S1) in the instant case and included in Exhibits A-50, Schedule OO1 and A-50, Schedule OO2."[312] He described subtransmission trunk line TRK4217 as an example of a thermal violation, where the cable is loaded to 115% of its normal rating.[313]

To vet that statement, MNSC asked in discovery for all instances of subtransmission equipment experiencing loadings above 100% of their normal rating. DTE's answer referred back to the discovery response filed as Mr. Deol's rebuttal Exhibit A-50, Schedule OO2 – and specifically to the column on pages 1-2 labeled "% Loading N-0 violation."[314]

Close review of this data in cross showed that it contradicts Mr. Deol's claims. For his TRK4217 example, the exhibit states that the normal rating is higher than the normal flow – not the other way around.[315] Therefore, the exhibit shows no N-0 loading violation for TRK4217, contrary to Mr. Deol's rebuttal testimony.[316]

The only other Subtransmission project from the capital exhibit for which DTE provided loading data is TRK4266.[317] Exhibit A-50, Schedule OO2 provides modeling results for TRK4266

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[311] Deol Rebuttal, 5 TR 1245.

[312] *Id*.

[313] *Id*. at 1246.

[314] Ex MEC-85 (discovery response MNSCDE-17.8).

[315] Deol Cross, 5 TR 1341-1342; Deol Exhibit A-50, Schedule OO2, p. 1, TRK4217 row.

[316] Deol Cross, 5 TR 1341-1332.

[317] Ex A-12, Sch B5.4, p. 14, line 19.

for both 2022 and 2026.[318] In Table 8 of his direct testimony, Mr. Deol listed the project driver as "Capacity," and stated that "Trunk 4266 is loaded to 108% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria."[319] The summer emergency rating is the single contingency scenario, referred to in the modeling results as the "%Loading N-1 violation."[320] Exhibit A-50, Schedule OO2 states that Trunk 4266's normal and emergency ratings are higher than its normal and emergency flows in both the 2022 and 2026 analyses.[321] That means Trunk 4266 does <u>not</u> violate DTE's thermal planning criteria in either the normal or single contingency scenarios, contrary to the statement in Table 8 of Mr. Deol's direct testimony.[322]

MNSC also asked DTE to identify any of the Subtransmission projects that address equipment that has caused customer outages due to thermal violations – but the Company refused to answer.[323]

In sum, even if DTE's planning criteria are valid, in the only instances where DTE provided loading data for Subtransmission equipment, the data contradicts the claims DTE makes in this case about the loading of that equipment. Mr. Deol said on cross that the loading data he relied on for his testimony may have been data from other analysis years, but MNSC plainly asked for the loading data he relied on for his testimony and DTE provided only Exhibit A-50, Schedule OO2. And for the rest of the Subtransmission projects included in this case, DTE provided no loading data at all. Thus, the Company has failed utterly to support its claims that the Subtransmission projects are needed for capacity reasons.

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[318] Ex A-50, Sch OO2, pp. 1-2; Deol Cross, 5 TR 1349.

[319] Deol Direct, 5 TR 1188.

[320] Deol Cross, 5 TR 1339-1340.

[321] Deol Cross, 5 TR 1350-1351; Ex A-50 Sch OO2, pp. 1-2, TRK4266 rows.

[322] *Id*.

[323] Ex MEC-86 (discovery response MNSCDE-17.9).

As to voltage violations, Mr. Deol mostly agreed that low voltage can impact customer service but does not generally pose a threat to DTE's equipment.[324] He indicated that it was possible for low voltage violations to impact the Company's equipment in unusual cases, but he could not think of any on the stand.[325]

e. Mr. Stephens' recommendations regarding Subtransmission.

Because DTE exaggerates capacity constraints on the subtransmission system, fails to support its capacity claims with loading data, and does no cost-benefit analysis, the Company has not demonstrated that these projects are reasonable and prudent investments.[326] Mr. Stephens recommended that the Commission disallow cost recovery on the Subtransmission projects that it has not already approved. Those projects are Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509.[327] All are coming online in 2024 and 2025 with total expenditures of $28.15 million.[328] Mr. Stephens also recommended that the Commission disapprove DTE's request for pre-approval of the $120 million total Subtransmission spending under the IRM for 2026 and 2027.[329] Finally, Mr. Stephens recommended that going forward, the Commission should require DTE to provide project-specific risk-informed cost-benefit and alternatives analyses for all Subtransmission projects over $10 million, before investing substantial capital beyond the conceptual and design phase.[330]

[324] Deol Cross, 5 TR 1358-1359.

[325] *Id*.

[326] Stephens Direct, 6 TR 4020.

[327] *Id*.

[328] Stephens Direct, 6 TR 4020; Ex A-12 Sch B5.4, p. 14, lines 14, 15, and 18.

[329] Stephens Direct, 6 TR 4020; Ex A-33 Sch X1.

[330] Stephens Direct, 6 TR 4020-4021.

f. The Commission did not approve the Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509 projects in U-21297.

As the last point in his rebuttal on Subtransmission, Mr. Deol asserts that the Commission approved the Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509 projects in Case No. U-21297.[331] His testimony includes a footnote that says:

> Regarding Subtransmission Redesign & Rebuild (Schedule B5.4, p. 11, line 114 [total of all subtransmission redesign and rebuild projects, including Tie 4105 and Trunk 3509]) states "the Commission finds the ALJ's recommendation to reject the proposed disallowances to be well-reasoned and supported by the record. The Commission adopts the ALJ's findings and conclusions on this issue and approves the 11-month bridge period and test year amounts."[332]

That is not an accurate reading of the Order in U-21297. The Order states that "DTE Electric reported 2021 spending of $21.5 million, estimated 2022 expenditures of $48.5 million, and projected 11-month bridge period and test year expenditures of $87.5 million and $102 million, respectively, for this cost category."[333] The Order states:

> The ALJ began by noting that most of these projects will not be complete within the test year and she recommended that they be excluded from rate base because they "do not generate a revenue requirement in this case[.]" PFD, p. 274. The ALJ stated that "only the projects on [Schedule B5.4, p. 11,] lines 42, 44, 46-51, 56-57, 67, 70, and 78 are projects for which DTE seeks rate recovery in this case. The total 11-month bridge and test year spending associated with these projects are approximately $24.6 million and $7.3 million respectively."[334]

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[331] Deol Rebuttal, 5 TR 1262.

[332] Deol Rebuttal, 5 TR 1262, fn. 43, citing Case No. U-21297, December 1, 2023, Order, p. 106.

[333] Order in U-21297, p. 104, citing Ex A-12 Sch B5.4, p. 11 in that case, which was admitted as Ex MEC-90 in this case.

[334] Order in U-21297, p. 105, quoting from PFD, p. 274.

Critically, Tie 4105 and Trunk 3509 were <u>not</u> included in the lines the ALJ listed from the capital exhibit in U-21297. Those projects were at lines 17 and 21 of that exhibit.[335] The Order went on:

> The ALJ found that "DTE has failed to support the reasonableness and prudence of the program, the individual projects, or the pace of spending on this program." *Id*. She noted that the total project cost was not provided for any project that would not be in-service by the end of the test year, and that the company made little attempt to justify its planning criteria and failed, in discovery, to provide the safety and reliability data on outages related to the reason for the program. The ALJ found as follows:
>
> > Since [MNSC] does not object to spending at the level of costs DTE is actually seeking to include in this rate case, this PFD does not find that a disallowance is necessary, but notes that should DTE present these projects for approval in its next rate case, or through an IRM, it needs to provide the details underlying its analyses, of the circuit upgrades, of the prioritization of circuits for upgrade, and an explanation for the pace with which DTE proposes to make these upgrades, along with an analysis of any alternatives considered, such as prioritizing interrupting protecting devices as endorsed by ITC. *Id*., p. 275. Thus, the ALJ recommended approval of 11-month bridge period and test year spending of approximately \$24.6 million and \$7.3 million, respectively.[336]

The Commission went on to hold that:

> While not agreeing that the in-service dates are dispositive of the issue, the Commission finds the ALJ's recommendation to reject the proposed disallowances to be well-reasoned and supported by the record. The Commission adopts the ALJ's findings and conclusion on this issue and approves the 11-month bridge period and test year amounts. *See*, PFD, pp. 274-275.[337]

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[335] See Ex MEC-90, Ex A-12 Sch B5.4 in U-21297.

[336] Order in U-21297, p. 105.

[337] *Id*. at 106.

In sum, for the Subtransmission program, the PFD in U-21297 recommended approval of $24.6 million in bridge period expenditures (out of $87.5 million DTE requested) and $7.3 million in test year expenditures (out of $102 million DTE requested). The PFD specified the lines in DTE's capital exhibit that presented the projects that totaled up to the amounts the PFD recommended approving. The Commission approved the PFD's recommended bridge period and test year amounts. The Order cited the pages of the PFD that listed the lines in DTE's capital exhibit, made the findings that DTE failed to support the program, and identified the $24.6 million and $7.3 million amounts. Conversely, while it disagreed with the PFD's view that in-service dates were dispositive of this issue, the Order never rejected or even expressed any disagreement with the PFD's findings, line numbers, or total expenditures approved. Thus, the Commission Order adopted the PFD's recommendations, and those recommendations did not include approval of expenditures for Tie 4105 Phase 3, Tie 4105 Phase 4, and Trunk 3509.

ii. Conversions, including CODI[338]

Conversions consist of converting 4.8kV circuits to 13.2kV and converting 8.3kV circuits in Pontiac to 13.2kV.[339] The 4.8kV conversions include City of Detroit Infrastructure (CODI) projects and also include "ISO downs" – 4.8kV circuits served by 13.2kV substations.[340] DTE plans to spend $78,755,000 on conversions in the 2025 projected test year, with the spending to be

[338] MNSC believes that the following portions of the record are relevant to these issues:

- Revised Direct Testimony of DTE witness Satvir Deol, 5 TR 1134-1175; Deol Rebuttal, 5 TR 1223-1234; Deol Cross Exam, 5 TR 1272-1328 and 1364-1390; Deol Confidential Cross, 5 TR 1285-1303;
- Exhibits A-12, Sch B5.4, pp. 14-16; Exhibit A-23, Sch M6; Ex A-23 Sch M8; Ex A-23 Sch M12; Ex A-33 Sch X1.
- Direct Testimony of AG-MNSC joint witness Dennis Stephens, 6 Tr 3998-4008;
- Exhibits MEC-5, 20, 77-86, 104, 107-120, and 121C.

[339] Deol Direct, 5 TR 1139.

[340] See Ex A-23 Sch M8, p. 110 for discussion of ISO downs.

included in rate base.[341] DTE plans to spend another $185.8 million on conversions in 2025 under the IRM.[342] DTE also requests preapproval under its IRM extension proposal to spend another $190 million on conversions in 2026, and $240 million in 2027.[343]

DTE plans to convert its entire 4.8kV system to 13.2kV and aspires to do so in the next 15 years.[344] The Company estimates the cost to will be over $25 billion in today's dollars.[345] That costs adds up to $11,000 per DTE customer.[346] And the estimate may be low – DTE reported a cost range for conversions in 2023 of $2.4 to $3 million.[347] Multiplying the average cost within that range of $2.7 million by DTE's 16,720 miles of 4.8kV circuits comes out to over $45 billion.[348]

In Case No. U-21297, DTE projected $172.6 million of conversions spending in the 2024 test year.[349] Staff recommended disallowing $115.9 million because DTE had not demonstrated it could ramp up conversions spending at such a rapid rate, and the Commission adopted Staff's disallowance.[350] The Commission also adopted Staff's $56.4 million disallowance for the 11-month bridge period.[351] The Commission approved DTE's proposed 2024 IRM conversions spending of $1.6 million and the Company's 2025 IRM conversions spending of $185.8 million,

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[341] Ex A-12 Sch B5.4, p. 16, line 115.

[342] Foley Revised Direct, 2 TR 119, Table 1; Ex A-33 Schedule X1.

[343] *Id*.

[344] Ex. A-23 Sch M7, pp. 120-121.

[345] Ex. A-23 Sch M7, pp. 120.

[346] This cost estimate may be low; the average cost per mile converted noted in the 2023 Technical Conference ($2.7 million) multiplied by 16,720 miles is over $45 billion. *See* Ex A-23 Sch M12 slide 34.

[347] Ex A-23 Sch M12, p. 34.

[348] Stephens Direct, 6 TR 3999, n. 21.

[349] Case No. U-21297, December 1, 2023, Order, p. 109.

[350] *Id*. at 111.

[351] *Id*.

but it rejected DTE's 2026 IRM conversions spending of $371.6 million by limiting the IRM to two years.[352]

DTE witness Satvir Deol provides details on the 2025 rate base conversion projects.[353] He summarizes some combination of safety, reliability, capacity, and operability justifications for each.[354] DTE's recently filed IRM plan for 2025 identifies conversion projects under the IRM for that year, but provides no information about the need, drivers, or justification for the specific projects listed – just the names and costs of the projects and generalities about the claimed benefits of conversions.[355] Many of the 2025 IRM projects are not in the Distribution Grid Plan, and so the record contains no support for those projects whatsoever.[356] DTE has not yet identified conversion projects for 2026 and 2027 under the IRM.

AG-MN witness Dennis Stephens testified that a moderate level of conversions spending that targets overloaded circuits could be warranted – but DTE has not justified the rapid pace and exorbitant cost of the Company's conversions spending beyond the test year.[357] Mr. Stephens notes that DTE has done no cost-benefit analysis for the conversions program, even though the Company should have enough data from completed projects by now to do such an analysis.[358] DTE's proffered justifications of reliability, safety, and capacity do not withstand close scrutiny. In

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[352] Case No. U-21297, December 1, 2023, Order, pp. 290-91; see Foley Direct in U-21297 for the $371.6 million number, 2 TR 66. See the IRM section of this brief for more discussion of the Commission's decision to limit the IRM to two years.

[353] Deol Direct, 5 TR 1146-50, Table 1; Ex A-23 Sch M6.

[354] *Id*.

[355] Ex MEC-24, pp. 5-7.

[356] Kent/Gibson, ISO Gilbert, ISO Kern, ISO Biddle, and ISO Venoy are listed in the 2025 IRM Plan but do not appear to be specifically identified in the DGP. The DGP discusses ISO projects as a category.

[357] Stephens Direct, 6 TR 4000, 4006-7.

[358] *Id*. at 4003.

addition, DTE's evidence lacks transparency – with information that conflicts across different exhibits, incomplete reporting of costs, and numbers that vary significantly from case to case.

Mr. Stephens did not challenge the test-year conversions spending but opposed preapproval of the 2026 and 2027 IRM spending levels because DTE has failed to support the need for such a rapid pace and so many dollars.[359] Even DTE's own internal communications acknowledge that "we're concerned about execution" when it comes to the spending levels for conversions.[360]

In rebuttal, DTE witness Deol attempted to back away from the 15-year goal, claiming it was only directional and that "[u]ltimately, the grid will be rebuilt at a pace required to support customer needs and affordability."[361] Mr. Deol asserted that "[t]he conversion investments in this case are supported by near-term drivers highlighted in my testimony, such as capacity needs, reliability improvements, and addressing aging and end of life infrastructure."[362] Mr. Stephens addressed each of DTE's reliability, safety, and capacity justifications in turn.

g. <u>Reliability.</u>

Mr. Stephens testified that reliability improvement is not a reasonable justification for the pace and scale of the conversions spending because DTE's own data showed that the reliability of its 13.2kV circuits (measured by SAIDI without MEDs) has been worse in recent years than its 4.8kV circuits.[363] Mr. Stephens did *not* claim that this data means there is never a reliability benefit from converting a circuit. But it does mean there is no *universal* reliability improvement from

[359] *Id*. at 4006.

[360] Ex MEC-26, p. 20.

[361] Deol Rebuttal, 5 TR 1226.

[362] *Id*.

[363] Stephens Direct, 6 TR 4001, using data DTE provided in Case No. U-21297.

converting – and so DTE needs to show on a project-level basis that there will be a reliability benefit from voltage conversion.[364]

In rebuttal, DTE witness Deol first acknowledged that "estimated reliability benefits vary with the specific data for each circuit and project,"[365] – which was Mr. Stephens' point. Mr. Deol claimed that "for the conversions that are included in the instant case, the average projected reliability improvement is estimated to be up to 90%..."[366] But when asked for the source analysis for this estimate, Mr. Deol had not analysis to provide.[367] He could only offer an analogy to a 65% reliability improvement in the hardening program.[368]

Mr. Deol also claimed that all-weather SAIDI is better on 13.2kV circuits than 4.8kV circuits.[369] However, if all-weather reliability is to be emphasized, DTE's all-weather data shows that SAIFI is better on 4.8kV circuits than 13.2kV.[370] Because the all-weather data also does not show a universal reliability improvement, the reliability benefits of conversions need to be evaluated on project basis – as Mr. Stephens testified.

Finally, Mr. Deol fell back on an argument that the reliability data are inconclusive because DTE plans to build the new 13.2kV circuits to a higher standard than the older 13.2kV circuits captured in the Company's reliability data.[371] But DTE – as the party seeking relief – has the burden of demonstrating that its projections and proposals are reasonable and prudent based on

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[364] Stephens Direct, 6 TR 4001.

[365] Deol Rebuttal, 5 TR 1227.

[366] *Id*.

[367] Ex MEC-78, p. 2, discovery response MNSCDE-13.11.

[368] *Id*.

[369] Deol Rebuttal, 5 TR 1227.

[370] Ex MEC-80, p. 8.

[371] Deol Rebuttal, 5 TR 1228.

substantial evidence.[372] If the data are inconclusive, then DTE as the proponent of those proposals fails to meet its burden. When the burden of proving a fact falls on one party, the other party does not have the burden of proving the opposite fact.[373]

h. Safety

As to safety, AG-MN witness Stephens agreed with Mr. Deol that "the design of the Company's 4.8kV circuits likely increases the risk that a downed conductor will remain energized if it falls to the ground."[374] However, Mr. Stephens noted that "this is a design condition that has existed on the Company's 4.8kV circuits since they were constructed," which "begs the question why all 4.8kV circuit conversions should be completed in the next 15 years."[375]

In rebuttal, DTE witness Deol states that Mr. Stephens "dismisses" the safety issue associated with 4.8kV circuits.[376] But plainly that is not accurate. Mr. Stephens acknowledged the issue but questioned whether it requires converting all 16,720 miles of 4.8kV circuits in 15 years at a cost of tens of billions of dollars.

Mr. Deol also stated that "reducing the risk associated from potential energized downed wires of the 4.8 kV ungrounded delta circuits should be a major focus and a justification for converting the 4.8 kV circuits."[377] However, when asked for any estimates or information DTE has regarding the relative safety risk of 4.8kV circuits compared to 13.2kV circuits, Mr. Deol

[372] *Dillon v Lapeer State Home & Training School,* 364 Mich 1, 8; 110 NW2d 588 (1961), *and BCBSM v Governor,* 422 Mich 1, 88-89; 367 NW2d 1 (1985); Case No. U-7484, August 30, 1983, Order, p. 10; Case No. U-8030-R, July 9, 1987, Order, pp. 16-17.

[373] *S C Gary, Inc v Ford Motor Co,* 92 Mich App 789, 803-804; 286 NW 2d 34 (1979).

[374] Stephens Direct, 6 TR 4002.

[375] *Id*.

[376] Deol Rebuttal, 5 TR 1229.

[377] *Id*.

referred to another discovery response that said no analysis had been performed.[378] The discovery response also attached the 4.8kV Technical Conference presentation.[379] But again, that presentation contained no estimate or analysis of relative safety risks – it just described the issue in the same general terms as Mr. Deol's testimony.

Finally, when asked for a list of the actual OSHA-reportable safety incidents associated with the 4.8kV system, DTE claimed not to have that information.[380]

i. Capacity

DTE's claims regarding capacity and circuit loading did not withstand close scrutiny. AG-MN witness Stephens noted that only 5.7% of the Company's 4.8kV circuits had peak loads that exceeded their day-to-day equipment ratings in 2022.[381] While Mr. Stephens agreed that overloading is a valid reason to upgrade circuits, the data does not justify DTE's rapid pace and high spending levels for converting all 4.8kV circuits to 13.2kV in a relatively short time period.[382]

In rebuttal, DTE witness Deol disagreed that the rarity of *actual* overloading undermines the Company's claims that its 4.8kV circuits lack sufficient capacity and must be converted.[383] Rather, he argued that DTE "must maintain a capacity margin for operating the system during maintenance and trouble events."[384] He referenced "not just day-to-day circuit capacity, but also the source substation capacity" – and asserted that "20% of the Company's 4.8kV substations

[378] Ex MEC-80, pp. 1-2.

[379] *Id*.

[380] Ex MEC-77, p. 7, discovery response MNSCDE-19.2f.

[381] Stephens Direct, 6 TR 4002.

[382] *Id*. at 4003.

[383] Deol Rebuttal, 5 TR 1230.

[384] *Id*.

operate over firm rating."[385] When asked for the basis of the claim that 20% of 4.8kV substations operate over firm rating, Mr. Deol made an estimate based on some project descriptions in the DGP.[386] But after examination in cross of the materials referenced in the DGP, Mr. Deol agreed that the information he relied on provides no basis for a claim that 20% of DTE's 4.8kV substations operate over firm rating.[387]

As to loading of the 4.8kV circuits themselves, DTE projects that only two of the 31 circuits it plans to convert in 2025 will be over their day-to-day rating in 2025.[388] And neither of these two circuits are over their day-to-day rating now – rather, they are projected to exceed their day-to-day after their load is adjusted upward based on assumed future conditions.[389] So just 2 of the 31 circuits DTE plans to convert in the test year are projected to be overloaded, and none of them are overloaded today.

DTE projects that another four of the 31 circuits it plans to convert will be over their "Distribution Design Order" (DDO) rating in 2025.[390] The DDO is a planning criteria DTE uses to determine when a circuit should be replaced for capacity reasons.[391] The DDO rating is claimed to allow for serving half of an adjacent circuit in the event of an outage while still remaining under the emergency rating for that circuit.[392] However, in reality, the DDO rating for all 1,945 of DTE's 4.8kV circuits is always the same: 3 MVA.[393] It does not matter what the circuit's actual rating is

[385] *Id.*, n. 17.

[386] Deol Cross, 5 TR 1326; Ex MEC-129, discovery response MNSCDE-17.5c.

[387] Deol Cross, 5 TR 1328.

[388] Deol Cross, 5 TR 1278; Ex MEC-77, pp. 1-2.

[389] Deol Confidential Cross, 5 TR 1296-1299; Ex MEC-121C, NDA CEII 17.5a attachment, lines 969 and 1023.

[390] Deol Cross, 5 TR 1279; Ex MEC-77, p. 2.

[391] Ex A-23 Sch M8, p. 90 of 274 (2023 DGP); Deol Cross, 5 TR 1307.

[392] *Id.*

[393] Deol Cross, 5 TR 1308; Ex MEC-121C, NDA CEII 17.5a attachment.

or how far above 3 MVA it may be – its DDO will always be 3 MVA.[394] If the circuit is over 3 MVA, DTE deems it loaded over its design capacity – no matter how much extra capacity the circuit actually has.[395]

The DDO limit is <u>not</u> an industry standard. DTE's Distribution Grid Plan states:

> The DDO limit is comparable to the Rural Utilities Service Standards, which are issued and maintained by the United States Department of Agriculture (USDA), which require system planning to account for planned and emergency load shifting. These are the minimum standards required for Rural Co-operatives to receive USDA financial assistance for projects and provide for ensuring capacity for switching as a baseline standard.[396]

As noted earlier, USDA Rural Utilities Service Bulletin 1724D-101A, titled "Electric System Long Range Planning Guide," was admitted in Case No. U-21297 after Mr. Deol cited it in his rebuttal – and was admitted again in this case.[397] In his cross exam in U-21297, Mr. Deol acknowledged that DTE does not rely on the USDA document for distribution planning – but rather, someone on his team found the document while doing research for this rebuttal in that case.[398] Further, the document is not written for a large metropolitan utility like DTE – it is written for rural electric cooperatives.[399]

In sum, DTE has not demonstrated that the high rate of conversions and associated expense is justified by reliability, safety, or capacity. The data on reliability are inconclusive at best. DTE posits a theoretical safety issue that AG-MN witness acknowledges, but when pressed the

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[394] Deol Confidential Cross, 5 1299-1300.

[395] Deol Confidential Cross, 5 TR 1300-1303; Ex MEC-121C, NDA CEII 17.5a attachment, lines 1155 and 1785.

[396] Ex A-23 Sch M8, Ex p. 90 of 274 (2023 DGP).

[397] Ex MEC-104, USDA Rural Utilities Service Bulletin 1724D-101A; Ex MEC-119, Deol Testimony in U-21297, pp. 148-155, transcript pp. 327-334.

[398] Ex MEC-119, pp. 148-150, transcript pp. 327-329; Deol Cross, 5 TR 1320-22.

[399] Ex MEC-119, p. 149; transcript p. 328; see also, Ex MEC-104, the USDA bulletin, which uses the word "cooperative" 70 times.

Company can produce no evaluation of the relative safety risk of 4.8kV circuits to 13.2kV ones, and no data on safety incidents at all.

Further, DTE has failed entirely to justify the pace of conversions based on capacity. What little data is in the record shows that none of the of the circuits DTE plans to convert are currently overloaded and very few will be overloaded after assuming increases in their loads. Very few of these circuits are even loaded over DTE's planning limit, and the method DTE uses to determine their planning limit is nothing more than a one-size-fits-all assumption whose only source is a loose analogy to a USDA bulletin that describes standards for rural electric cooperatives looking to borrow money from that agency. DTE has wholly failed to meet its burden on this issue; the Commission should disapprove the IRM spending amounts for conversions in 2026 and 2027; and the Commission should direct the Company to slow the plans for conversions going forward and justify each conversion with project-specific information showing specific need.

j. Transparency concerns.

AG-MN witness Stephens also noted that the spending projections for conversion projects lack transparency.[400] Most of them are multi-million-dollar projects that span many years.[401] Prior to the Commission's Order in U-21297, DTE did not present the total cost for projects that span beyond the projected test year.[402] Even now, however, cost projections for the projects vary widely from case to case.[403] Discussing the Almont 4.8kV (Midas) conversion project as an example, Mr. Stephens concluded that "[g]iven the timeline, scale, and discretionary nature of conversion

[400] Stephens Direct, 6 TR 4003.

[401] *Id.*; see also, Ex A-12 Sch B5.4 pp. 14-16.

[402] Stephens Direct, 6 TR 4004.

[403] *Id.*

projects, DTE should present robust support for conversion projects at the outset."[404] Doing so would ensure regulatory review of these discretionary projects occurs before the Company incurs substantial costs.[405]

In rebuttal, DTE witness Deol responded by identifying a total project cost for the Almont-Midas project of $30.7 million in two of the project documents.[406] However, Mr. Deol did not respond to the larger points that project costs change from case to case and the Company should provide clear support for the reasonableness and prudence of the projects at the beginning – not somewhere in the middle.

A closer look at the Almont-Midas project in cross exam confirmed the lack of transparency in DTE's exhibits. The capital exhibit for the project presents a total of $24.1 million in expenditures from 2022 through 2025.[407] One has to go back to exhibits in Case Nos. U-21297 and U-20836 to find expenditures of $5.6 million and $0.5 million in years prior to 2022.[408] Even then, however, the total spending amounts to $30.2 million – not the $30.7 million cited by Mr. Deol.[409] He explained that the missing $0.5 million is missing land acquisition costs, which the Company would have occurred even farther back in the past.[410] To complicate matters further, the 2023 Distribution Grid Plan contains entirely different spending amounts for the Almont-Midas project than the capital exhibit does. The capital exhibit lists $6 million in 2024 and $1 million in

[404] *Id*. at 4005-4006.

[405] *Id*. at 4006.

[406] Deol Rebuttal, 5 TR 1232-1233.

[407] Deol Cross, 5 TR 1367-68; Ex A-12, Sched B5.4, line 41.

[408] Deol Cross, 5 TR 1368; Ex MEC-112, U-21297 Ex A-23 Sch M5, pp 1-5, lines 294-297; Ex MEC-115, U-20836 Ex A-12 Sch B5.4, p. 10, line 56.

[409] *Id*.

[410] Deol Cross, 5 TR 1368-1369.

2025, while the DGP says $1 million in 2024 and $0 in 2025.[411] Mr. Deol said he could not explain the disparity without consulting with the person who put together the table in the DGP.[412]

Another example of conflicting information and lack of transparency is the Islandview Substation CODI project. Mr. Deol's direct states that Islandview is a three-phase project that will occur over a timeline of 2020 to 2031.[413]

For Phase 1, Exhibit A-23, Schedule M6 lists a total project cost for of about $23.9 million.[414] Exhibit A-12, Schedule B5.4 shows historic spending of about $12.3 million for Phase 1 in 2022, $7.7 million in 2023, $7,000 in 2024, and no spending in 2025 – for a total of about $20 million.[415] Mr. Deol testified that the other $4 million for Phase 1 would have been spent before 2022.[416]

For Phase 2, Exhibit A-23, Schedule M6 shows spending of about $59 million, and the total of the spends in Exhibit A-12, Schedule B5.4 more or less match that figure.[417]

For Phase 3, however, Exhibit A-23, Schedule M6 shows total spending of about $65 million.[418] But the capital exhibit shows only $45,000 of spending in 2022 for Phase 3, and no spending for any other years.[419] Mr. Deol testified that all other expenditures for Islandview Phase 3 would be in future years beyond 2025.[420] But the capital exhibit indicates an in-service date for

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[411] Deol Cross, 5 TR 1369-70; Ex A-23 Sch M8, p. 236 of 274 (2023 DGP).

[412] Deol Cross, 5 TR 1369-70.

[413] Deol Direct, 5 TR 1166.

[414] Ex A-23 Sch M6, p. 159; Deol Cross, 5 TR 1380.

[415] Deol Cross, 5 TR 1380.

[416] *Id*. at 1381.

[417] *Id*. at 1382.

[418] Ex A-23 Sch M6, p. 167; Deol Cross, 5 TR 1382.

[419] Ex A-12 Sch B5.4, p. 14, line 33; Deol Cross, 5 TR 1382.

[420] Deol Cross, 5 TR 1383.

Phase 3 of 2025, which Mr. Deol could not explain other than assuming that the date must be an error.[421]

Thus, the record in this case for Islandview indicates that it will perhaps cost somewhere in the vicinity of $148 million total over three phases, but large amounts of that spending are not presented in this case because some of the spending took place earlier than the figures documented in the capital exhibits and some of it presumably will take place later – assuming that the in-service date is wrong and not the spending figures. Adding further confusion, the capital appropriation request form (CARF) for Islandview Phase 1 indicates that it will include "7 distinct projects executed over the next ten years"[422] – rather than the 3 phases listed in the exhibits. It is unclear whether the additional phases mean that there is additional spending beyond the $148 million total from Phases 1-3. The GPM model reports a total project cost for Islandview of $225,872,109 – about $78 million more than the total spending in the capital exhibit.423 Further, Islandview does not appear in the Top 50 projects in the Distribution Grid Plan and, except for a few bullet points, it does not appear in the DGP at all.[424]

In sum, the record in this case provides unclear and contradictory information about what Islandview will cost, how many phases it has, and when it will be in service. Query how and when a determination can be made as to whether the Islandview project is reasonable and prudent? DTE's presentation of these projects is a muddled and confusing mess, and AG-MN witness Stephens is right that the Commission needs to direct DTE to clean it up going forward.

[421] Ex A-12, Sch B5.4, p. 14, line 33; Deol Cross, 5 TR 1383.

[422] Ex MEC-108,

[423] Exhibit A-43, Schedule HH4, GPM Results tab, line 31.

[424] Ex A-23 Sch M8, pp. 211, 259 of 274 (2023 DGP; Deol Cross, 5 TR 1383-85.

5. Technology and Automation

i. Distribution Automation [425]

DTE proposes to significantly increase spending on its Distribution Automation program, which was formerly split into the 4.8kV Automation and 13.2kV Automation:[426]

	2022	**2023**	**2024**	**2025**	**2026 (IRM)**	**2027 (IRM)**
U-21534 Investment Plan	$5.506 million	$27.104 million	$21.188 million	$125.625 million	$105.000 million	$180.000 million
U-21297 Approved IRM			$24.375 million	$26.406 million		

Per the 2023 DGP, DTE's investment plan for Distribution Automation continues to ramp even further to $469 million in 2028.[427] The 2023 DGP shows the Distribution Automation, at $1.192 billion over the 5-year DGP period, is the costliest of all DTE's proposed distribution system investments in the DGP.[428] While details are scant, it is worth noting that $20 million of the planned $150 million investment in Distribution Automation in 2025 appeared to materialize through a text exchange between an unidentified DTE staff person and Ed Karpiel in the process

[425] MNSC believes the following is the record on this issues:

- Direct Testimony of DTE witness Shannen M. Hartwick, 4 TR 635-47; Rebuttal Testimony of Ms. Hartwick, 4 TR 823-37; Cross Examination of Ms. Hartwick, 4 TR 860-78; Confidential CEII Cross, 4 TR 885-93;
- Ex A-12 Sch B5.4; Ex A-23 Sch M7, M8; Ex-A-53 Sch RR1, RR2;
- Direct Testimony of AG, MEC & NRDC witness Dennis Stephens, 6 TR 4021-25;
- Exs MEC-11, 59-66;
- Direct Testimony of CEO witness Curt Volkman, 6 TR 3238-39, 3249-50;
- Direct Testimony of ABATE witness James R. Dauphinais, 6 TR 3380-82;
- Direct Testimony of Staff witness Nicholas M. Evans, 6 TR 5234, 5237.

[426] Ex A-12 Sch B5.4 p. 17 line 2; Ex A-33 Sch X1 line 6; Harwick Direct, 4 TR 644.

[427] Ex A-23 Sch M8 p. 136 of 274, Table 10.1.3.

[428] Ex A-23 Sch M8 pp. 162-64 of 274, Exhibit 11.0.2, 5-Year Total column.

of developing the U-21534 rate case proposal.[429] It's unclear if this is a typical practice to develop rate case spending proposals at DTE.[430]

Company witness Hartwick supports the Company's Distribution Automation investment plan.[431] DTE is proposing to deploy G&W Electric's Viper reclosers at circuit midpoints to isolate and limit the scope (number of affected customers) when outages occur, and at circuit tie points at the end of the circuit to facilitate rerouting damaged circuit sections to adjacent circuits.[432] DTE notes its proposed deployment of these reclosers is unique in two ways: (a) most utilities don't have ungrounded 4.8kV delta system as DTE does, and Viper reclosers promise to reduce the risk of energized wire downs on the 4.8kV system; and (b) the potential to improve service restoration by adding automation to circuits with existing connections.[433] DTE anticipates extensive circuit automation will improve reliability and developed a Distribution Automation model to prioritize circuits (the DA Prioritization model).[434] In 2023, DTE installed 70 reclosers in the second half of the year; a full year of performance data is unavailable. DTE anticipates using actual outage data in 2024 to track reliability benefits of automation.[435]

AG-MN witness Dennis Stephens supported the Company's efforts to develop a cost-benefit model and its initial roll-out of the new reclosers but opposed the planned rapid investment

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[429] Foley Cross, 2 TR 216-218; Ex MEC-26, pp. 50, 49 (Query from Mr. Foley to Mr. Karpiel: "How should I think about the $130M you have on your table below [for circuit automation] vs. the $150M in the case/IRM?" Response from Mr. Karpiel: "Someone texted me to add $20m to the automation budget in 2025 and it didn't make its way into that file yet, so yes $150m for 2025").

[430] Foley Cross, 2 TR 218.

[431] Hartwick Direct, 4 TR 637-647; Ex A-23 Sch M7 pp. 46-49; Ex A-23 Sch M8 (2023 DGP), pp. 136, 138-39 of 274.

[432] Hartwick Direct, 4 TR 638-639.

[433] *Id.* at 639-641.

[434] *Id.* at 643-645.

[435] *Id.*at 646-647.

ramp-up in 2025 and continuing into the IRM years.[436] He noted that reclosers are most often cost-effective when tie lines are already built but may become cost in-effective where new tie lines are required given the construction costs of new tie lines.[437] Finally, he found dubious DTE's assertion that costly Automation is a cost-effective way reduce energized wire downs on 4.8kV circuits, and noted DTE already has programs to reduce wire-downs on 4.8kV circuits (ETTP, Hardening, DLPD removal, PTMM).[438] He recommended the Company develop a benefit-cost model (as opposed to a prioritization model) with historic data to support safety (wire down) and other reliability benefits, and maintain current spending levels until such an analysis is available.[439]

In rebuttal, Company witness Harwick objects to Mr. Stephens' concern that the Company has not provided support for its position that Viper deployment provides measurable safety benefits for the 4.8kV system.[440] The rebuttal maintains the Vipers have the capability to detect wire downs, the circuits they will be installed on in 2025 have documented wire down events, and the DA Prioritization model lists historical wire downs on each circuit planned for reclosers in 2025.This is not responsive to Mr. Stephens' testimony, it just reiterates the projection that future Automation installations will in the future reduce wire downs on the 4.8kV lines. Once the Company deploys reclosers on 4.8kV circuits, it should present historic data documenting wire down reductions. Of course, the evaluation must control for trimming and compare costs and benefits to other programs. The rebuttal simply confirms that it is premature to approve the spending ramp-up until after there is historic data to evaluate whether projected wire down reductions in fact materialized.

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436 Stephens Direct, 6 TR 4021-4025.

437 *Id.* at 4021-4022.

438 *Id.* at 4023.

439 *Id.* at 4024.

440 Harwick Rebuttal, 4 TR 825-828.

The rebuttal notes that Vipers have detection capabilities that support the Company's expectation the reclosers will provide new safety benefits and they are transferable from 4.8kV to 13.2kV circuits.[441] This is also non-responsive. As Mr. Stephens noted, other programs and substantial investments have been dedicated to 4.8kV circuit wire down reductions, so the number of energized wire downs on these circuits should be decreasing. DTE should evaluate those investments plus evaluate incremental safety and reliability benefits of costly recloser installation before the Commission approves the proposal to add $100 million to this new program in 2025. That the Vipers may transfer from 4.8kV to 13.2kV with circuit conversion is not redemptive. Even if the equipment is not obsolete, some portion of labor and installation costs will be sunk and replicated with conversion.

The rebuttal next addresses the value of reclosers.[442] The testimony largely repeats direct testimony, noting Vipers have been tested, including with a live field installation, and approved for use on the system and are well suited to storm conditions. The Company plans to use its model to optimize circuit-specific specifications and evaluate cost-effectiveness on individual circuits. And the Company claims a 2016 DOE report supports its projected benefits. All of these potential attributes and benefits of reclosures support program continuation and evaluation, but none support a massive infusion of an additional $100 million investment in Automation in 2025 – and nearly double that by 2027. Every asserted attribute of Vipers and the Company's DA Prioritization model warrant scrutiny based on DTE field deployment and historic circuit-specific data. Even the Company decision to pursue Vipers without bidding or apparent evaluation of alternative equipment warrants scrutiny.[443] The Company asks the Commission to place a nearly $400 million

[441] Hartwick Rebuttal, 4 TR 827.

[442] Hartwick Rebuttal, 4 TR 828-832.

[443] Ex MEC-62.

bet on Vipers and the credibility of its DA Prioritization model. The prudent approach is for the Company to first demonstrate the benefits of Vipers in measurably reducing energized wire downs and fewer customers interrupted on circuits with reclosure that are also already on regular ETTP cycles and already have DPLD wire removed. The Company identifies benefits of Vipers but has no evidence of whether and to what extent this technology, once deployed to DTE circuits, will achieve the promised benefits.[444]

The final part of the rebuttal defends the DA Prioritization model as sufficient to support test year investments without the need to develop a cost-benefit model.[445] The testimony recites the Company's expectations for reliability benefits that will flow from test year investments. The flaw in the Company's position is that the Company's models[446] depend entirely on projections of potential reliability benefits – reductions in customer minutes of interruption (CMI) and avoided wire downs – that are unsupported and unvalidated. The Company has insufficient data or for other reasons has not assessed the reliability and safety benefits on lines where it has installed Vipers.[447]

[[[redacted]

[444] See Ex MEC-61 (no assessment of wire down reductions); Ex MEC-62, p. 2 (citing potential safety benefits but no evaluation of cost-effectiveness).

[445] Hartwick Rebuttal, 4 TR 833-837.

[446] Ex MEC-72, Reliability Model, Automation Benefits by Ckt Tab; Ex A-53 Sch RR2, CEII Distribution Automation model, [[[redacted]]].

[447] Exs MEC-61, 62, 65.

[448] Hartwick Cross, CEII Transcript, 4 TR 889-891.

[449] Ex A-53 Sch RR2 [[[redacted]]].

[redacted]]]

The rebuttal cites a 2016 Department of Energy (DOE) report to support DA Prioritization model reliability benefits assumptions, but the report does not actually support the Company model.[452] As recited in rebuttal, the September 2016 DOE Report discusses fault location, isolation, and service restoration (FLISR) technologies and indicated that FLISR operations reduced customer interruptions and CMI by 55% and 53% respectively and DA technologies improved SAIFI by "17%-58%."[453] The cited report does not indicate when, where, what utility, what circuit voltage, weather conditions, what cost, or any other information about the reported reductions. It subsequently reports "FLISR operations showed [a] up to 45% reduction in customers interrupted [and] [b] up to 55% reduction in [CMI],"[454] again without citations or sources. The testimony also references storm outages in Chattanooga TN in 2012 and 2014 were shortened as a result of "FLISR and smart meters," but provides no additional information about circuits, conditions, voltage, and more.[455] Based on these factoids, the rebuttal concludes, "Distribution Automation equipment investments improved reliability, in that less customers were affected by outages and outages were shorter in duration." This says nothing of circuit-level cost effectiveness or the reasonableness of the assumed CMI reductions in the DA Prioritization model.

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[450] Hartwick Cross, CEII Transcript, 4 TR 891-893; Ex A-53 Sch RR2, [[[redacted]]].

[451] Hartwick Cross, CEII Transcript, 4 TR 892.

[452] Hartwick Rebuttal, 4 TR 662-709; Ex MEC-60 (2016 DOE Report).

[453] Hartwick Rebuttal, 4 TR 835 n. 28 (citing DOE (2016 Sep) report, p. 5); Ex MEC-60 (2016 DOE Report).

[454] Ex MEC-60, p. 20.

[455] Hartwick Rebuttal, 4 TR 836 (citing DOE report, p. 6).

The 2016 DOE report concludes with some key lessons and conclusions that are more instructive than the uncited contextless outage blurbs in the call-out boxes. It states unequivocally that reliability benefits and cost-effective of FLISR and reclosers are utility-specific:

> **Return on Investment for a Specific Technology or Function is Utility-Specific:** Cost-effectiveness depends on a number of factors, including project scale, the functionality of individual devices, the utility's learning curve, and the need for wholly new software and systems or the ability to retrofit. Larger scale projects saw the most significant results and could better leverage foundational investments in communications infrastructure and information systems integration.[456]

It goes on to explain the importance of baseline and post-deployment data:

> The best way to evaluate the impact of DA technologies on system reliability is to compare reliability indices before and after deployment using a well-established pre-deployment baseline. Unfortunately, many SGIG utilities had trouble establishing accurate, reliable pre-deployment baselines from which to measure performance improvements. It is recognized that the process of developing a baseline is complex and time consuming for utilities. Simply comparing reliability indices from year to year—rather than against a baseline—cannot effectively measure the full impact of DA investments. Utilities that **did** compare results against pre-deployment baselines reported significant reliability improvements with DA. In 2013 alone, three utilities reported SAIFI improvements of 17 percent to 58 percent compared to pre-deployment baselines (see Figure 8). SAIFI is the primary metric used to track the frequency of outages. **The impact of DA on reliability depends on the system design and its potential for improvement.** Utilities that applied DA technologies to the worst feeders first saw a larger relative impact than utilities who applied DA to feeders with less room for improvement.[457]

The 2016 DOE report supports grid modernization, including Distribution Automation, but it does not support DTE's assumed CMI reductions from Vipers nor DTE's plan to increase spending by

[456] Ex MEC-60 (2016 DOE Report), p. 7.

[457] Ex MEC-60, p. 24 (emphasis in original).

nearly $400 million in 3 years on reclosers. Rather, the 2016 DOE report supports slowing down the Viper deployment plan to assess its benefits based on DTE's experience with Vipers.

DTE provided in discovery data evaluating the reliability benefits associated with reclosers it installed in 2022 and 2023.[458] The evaluation includes SAIDI ex-MEDs for 199 circuits installed in 2022 or 2023, providing the annual minutes for 5 years preceding installation, year of installation, and year following installation. The data provides SAIDI ex-MED minutes the year following recloser installation for the sole circuit installed with reclosers in 2022 (REDFD1064).[459] That one circuit experienced substantially *worse* SAIDI ex-MEDs the year after installation than the year of installation and each of the 3 years immediately preceding Viper installation:

ExMED SAIDI (min)				
Install Year - 3	**Install Year - 2**	**Install Year - 1**	**Install Year**	**Install Year + 1**
141	69	120	48	173

The Company resists the recommendation to develop a circuit-specific benefit-cost analysis to support Distribution Automation on the basis it already has the DA Prioritization model, but prioritizing which circuits should be upgraded first does not demonstrate that installing reclosers on any circuit is cost-effective. The Distribution Automation program is still in its infancy and lacks historical data to support the reasonableness and prudence of massively increasing test year and IRM year investments. Additional programs underway offer reliability and safety benefits, particularly on 4.8V circuits, making it premature to approve increasing spending on Distribution Automation in this proceed. Moreover, the distribution audit warrants assessment before committing to such a costly and yet-unproven program for DTE. The Commission should

[458] Ex MEC-65; Hartwick Cross, 4 TR 875-878.

[459] Ex MEC-65, p. 2, row 3.

maintain the level of spending approved in U-21297 ($24.449 million), which is nearly triple spending in historic year 2022.

One final point about Distribution Automation bears mention, which further supports imposing a spending pause now. According to DTE, its plan to install thousands of reclosers through the Distribution Automation program is in turn driving the Company's $100+ million Grid Automation Telecommunication investment.[460] DTE asserts that much of its pole top and other equipment is not yet adequately connected for communications, so the Company needs to upgrade the communications network then connect it to equipment.[461] As discussed below, the Commission found DTE's plan to address communications gaps – i.e., a privately owned fiber network – insufficiently supported in U-21297 and disallowed 2024 spending, though the Company spent the planned investment anyway. As discussed below, the presentation in this case remains indeterminate and deficient. Two conclusions can be drawn here. First, it seems DTE does not have infrastructure in place to support Distribution Automation deployment, particularly at the audacious scale it is proposing. That supports a delay in Viper deployment. It also renders even more speculative its claims about the performance and projected benefits of Vipers on its system. The Commission should pause spending on both Distribution Automation and Grid Automation Telecommunications until DTE has developed a comprehensive assessment of the full costs and a realistic assessment of benefits to facilitate evaluation of whether the investment is worth the benefits, particularly in light of other ongoing investments (ETTP, Hardening, PTTM) those on the horizon – i.e., potential 4.8kV conversion.

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[460] Ex A-23 Sch M7, p. 74; Ex A-12 Sch B5.4, p. 17 line 6; Ex A-23 Sch M8 (2023 DPG), p. 137 of 274, Exhibit 10.1.3.

[461] Ex A-23 Sch M7, p. 74.

ii. Grid Automation Telecommunications [462]

Starting in 2021 in U-20836, DTE has been rolling out a project to deploy a network of Company-owned fiber to connect substations and facilitate communications.[463] In Case No. U-21297, MNSC witness Alvarez opposed the Company's proposed investment on the basis DTE failed to provide a comparative analysis, evaluate alternatives, seek bids, and otherwise failed to support the project's reasonableness.[464] The Commission adopted the ALJ's analysis and recommendations to disallow test year (12 months ending November 30, 2024) spending:[465]

> The ALJ found that DTE Electric failed to support the reasonableness and prudence of these investments and recommended adoption of MNSC's reduction. The ALJ noted that DTE Electric expanded the scope of the program from the 500 miles of fiber and 230 substations proposed in Case No. U-20836 to the present proposal for 630 miles and 400 substations in the test year. She found that the company's reference to section 3 of the DGP for support was not useful. See, Exhibit A-23, Schedule M7, pp. 374-377. The ALJ noted that DTE Electric made no mention of O&M savings, and recommended that, since the project was approved by the Commission for the 500-mile scope, the company should be allowed to "continue the project through the bridge period to complete the scope of the undertaking presented in Case No. U-20836" but that test year spending should be denied inclusion in rate base. PFD, p. 311. She further found that the company should be required to provide an analysis of alternatives when requesting further extensions of the fiber network.

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462 MNSC believes the following is the record on this issue:

- Direct Testimony of DTE witness Shannen M. Hartwick, 4 TR 647-74; Rebuttal Testimony of Ms. Hartwick, 4 TR 837-55;
- Ex A-12 Sch B5.4; Ex A-23 Sch M7, M8;
- Direct Testimony of AG, MEC & NRDC witness Paul Alvarez, 6 TR 3972-8;
- Ex MEC-8, 11.

463 Case No. U-20836, November 18, 2022, Order, pp. 138-40; Case No. U-21297, Hill Direct, 5 TR 2772 (describing fiber installation to connect substations starting in 2021).

464 Case No. U-21297, December 1, 2023, Order, p. 120.

465 Case No. U-21297, December 1, 2023, Order, pp. 120-21.

The Commission noted DTE may seek funding in future cases "with adequate evidentiary support."[466]

Notwithstanding the disallowance of 2024 investment ordered in U-21297, DTE proposes to continue its Grid Automation Telecommunications investment full boar, with more planned for 2026 through 2028:[467]

2021	2022	2023	2024	Test Year 2025	2026	2027	2028
$10.239 million	$16.328 million	$21.346 million	$16.900 million	$15.000 million	$13.8 million	$12.5 million	$11.0 million

Notably, DTE increased 2023 spending above what it planned and the Commission approved in U-21297 – the Commission approved $19.100 million for 2023 but DTE pulled $2.246 million forward from 2024.[468] DTE's proposal for 2024 is on par with what it proposed and the Commission disallowed for 2024 in U-21297.[469]

Company witness Hartwick supports the Company's proposal to continue the program, notwithstanding the prior order.[470] In a nutshell, DTE is continuing with its plans set out in U-21297 to expand the Company-owned fiber-optic data communications network through connections to substations.[471] In U-20836, DTE presented the first 500 miles of Company-owned private fiber installation to be installed through 2023; in U-21297, DTE added 130 miles of installation to be installed through 2024; now in U-21534, DTE is planning in 2025 to install an

466 *Id.* at 122.

467 Case No. U-21297, Ex A-12 Sch B5.4 p. 12 line 6 (2021 spend); Ex A-12 Sch B5.4 p. 17 line 6; Ex A-23 Sch M8 (2023 DGP), p. 137 of 274, Exhibit 10.1.3 (2026-2028 spend plan).

468 Ex A-29 Sch M2 Revised, p. 8 line 6.

469 In U-21297, DTE forecast $16.861 for calendar year 2024, which the Commission disallowed, as noted above.

470 Hartwick Direct, 4 TR 647-677.

471 Hartwick Direct, 4 TR 651-654.

unspecified number of miles of private fiber.[472] DTE will substantially complete its fiber network installation by 2028;[473] after 2025, the plan is to use the network as the base for a "last mile" wireless communication expansion to communicate to smart meters, distribution automation, and other facilities and assets.[474] The total projected program investment is $107 million from 2022-2028.[475] DTE plans in the future to develop a benefit-cost analysis for post-2025 investments.[476]

AG-MN witness Alvarez again opposed the Company's Grid Automation Telecommunications investment plan and recommended the Commission disallow historic costs incurred to date and reject proposed test year spending.[477] He noted DTE's proposed investment presumes that many new technologies require real-time communications and that Company-owned options provide the best combination of speed, control, and security, and he debunked both rationales. He found DTE's review of alternatives deficient and insufficient to meet the directive in U-21297 and to support $107 million in project spending. He based his disallowance recommendation on the fact that DTE did not develop a benefit-cost analysis nor a make versus buy analysis to support its spending or the overall plan, did not comply with the directive to analyze alternatives to its overall plan, and failed to produce the overall plan.[478] Mr. Alvarez further recommended the Commission direct DTE to solicit an independent expert to compare various telecommunication options, including the risks and lifecycle costs of each. Mr. Stephens

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[472] Hartwick Direct, 4 TR 669-73.

[473] Ex A-23 Sch B8 (2023 DGP), p. 141 of 274.

[474] Hartwick Direct, 4 TR 651-4.

[475] Ex A-12 Sch B5.4, p. 17 line 6 (2022-2025); Ex A-23 Sch M8 (2023 DGP), p. 137 of 274, Exhibit 10.1.3 (2026-2028).

[476] Hartwick Direct, 4 TR 674; Ex MEC-8, p. 3.

[477] Alvarez Direct, 6 TR 3974-8.

[478] Alvarez Direct, 6 TR 3978.

recommended disallowing the Company's proposed 2024 and 2025 planned spending in this program.[479]

In rebuttal, witness Hartwick notes discrepancy between Mr. Alvarez' recommendation to disallow all program spending and Mr. Stephens' recommendation to disallow (again) 2024 and 2025 planned spending.[480] MNSC concedes the recommended disallowances differ as Mr. Stephens did not recommend rejecting pre-2024 spending. The Commission should adopt Mr. Stephens' recommendation between it is consistent with the Commission's order in U-21297 disallowing 2024 spending but not pre-2024 spending. MNSC maintains that Mr. Alvarez is correct that 2022 and 2023 spending was unreasonable but acknowledges the Commission in U-21297 approved pre- test year spending.

Next in rebuttal, Ms. Hartwick defends the Company's slim presentation of post-2025 plans for this project.[481] The rebuttal repeats what was disclosed about the Grid Automation Telecommunications plan for 2025-2028 in direct testimony, the 2023 DGP, and discovery, and reiterates the plan. The rebuttal implies the only thing not provided is "exact routes to be deployed after 2025," which will be prioritized based on a to-be-developed cost benefit analysis.[482] But there's no there there. The Company has not disclosed how many miles and substations it plans to connect with private fiber from 2022 through 2028, and what's left after 2025. DTE has 789 substations in its system, with 181 connected by Company-owned fiber; it's unclear if the plan is to connect all of them with Company-owned fiber or which subset, and why.[483] DTE has not

[479] Stephens Direct, 6 TR 4029; Ex MEC-11.

[480] Hartwick Rebuttal, 4 TR 838-40.

[481] Hartwick Rebuttal, 4 TR 842-4.

[482] *Id.* at 842.

[483] Kryscynski Direct, 3 TR 304, Table 1; Ex MEC-8, p. 1.

disclosed the scope of pole connects, which apparently may continue beyond 2028.[484] The DGP says "substantial completion of the fiber installation is expected in 2028," but does not describe what other work – beyond fiber installation – is contemplated, nor why, nor where. The direct testimony says the project focus "[t]hrough 2025" is on "expanding the backhaul network," then in the future it will be working on the "last mile network."[485] But the rebuttal says "[i]nvestments in 2026 through 2028 will focus on extending the backhaul network" and post-2028 investments "will focus on building out the last mile network."[486] There is no map, no list of substations, no discussion of where DTE's private fiber will replace existing network and where it will fill gaps nor how extensive the "backhaul" and "last mile" networks may be. Grid Automation Telecommunications has the hallmarks of a program – a continuing annual investment. Mr. Alvarez is right – the Company has not disclosed a Grid Automation Telecommunications plan, it has disclosed a concept plus planned spending for 2022 through 2028. Context is important, the Company has not provided it.

The rebuttal next maintains the alternatives evaluation presented in direct testimony satisfies the Commission's directive in U-21297.[487] The presentation includes a series of self-serving conclusions, unsupported by research, data, bid results, benchmarking, or other evidence, that largely reiterates the Company's rationale and assertions presented in U-21297, which the Commission found deficient. In U-21297, Company witness Hill dismissed publicly owned third party telecommunications in favor of private fiber for these reasons:[488]

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[484] Hartwick Rebuttal, 4 TR 844.

[485] Hartwick Direct, 4 TR 648.

[486] Hartwick Rebuttal, 4 TR 844.

[487] Hartwick Rebuttal, 4 TR 845-7.

[488] Case No. U-21297, Hill Direct, 5 TR 2773-4; Hill Rebuttal, 5 TR 2801-5.

- Faster restoration times as a result of the ability to remotely control and operate critical reliability equipment;
- Reduced cyber risk from malevolent electromagnetic interference;
- Public use of wireless communication bands to unlicensed public use creates interference and reduces reliability and capability;
- Limited traffic on private fiber improves the ability to detect, isolate, and terminate any suspicious behavior;
- There is not full coverage in the DTE service territory;
- Service quality and bandwidth vary within service areas;
- Telecom company charges a cost to build out its network to reach the site, which means paying for both upfront costs plus leased services;
- There can be dead zones and poor reception inside buildings;
- Reliability may suffer with public systems because they are designed to transmit data that can be lost without losing the intent of communication whereas fiber cable is better to transmit information critical to utility operations cannot be lost in communication;
- Public carriers can upgrade technology at their discretion, and unplanned upgrades can negatively impact DTE, providing the example when carriers upgraded between 2G, 3G and 4G and abandoned parts of DTE service area and caused DTE and other utilities to expend "to redesign and invest in a brand-new AMI meter mesh backhaul at a cost of nearly $35 million."
- Fiber is more secure than wireless, which networks can be blocked or emulated. "The mere fact that multiple users and shared traffic exists on wireless networks makes them inherently less secure than having dedicated networks."

Company witness Hartwick offers the same rationales related to service quality, unplanned outages, faster restoration, coverage, cost, security, reliability, networks extensions mean both infrastructure buildout costs plus additional lease costs," and even the same examples ("the 3G to 4G technology transition required DTEE to invest over $36M").[489] These are the same general and conclusory rationales offered in U-21297. The Harvey Ball figures visualize the unsupported and unexplained conclusions of internal SMEs following their discussion and ranking of six options.[490] It shows, for example, Staffing has identical Life Cyle Factor scores for Public Cellular, Leased Fiber, and Private Fiber, which is illogical. Private Fiber gets a perfect score for Ongoing Operating

[489] Hartwick Direct, 4 TR 656-62.

[490] Hartwick Direct, 4 TR 664-6.

Costs while Public Cellar gets only ¼ score – there is no support or explanation. DTE SMEs agreed it would be better for DTE to install a private fiber network than any alternative. That is not a robust or credible alternatives analysis.

The rebuttal next responds to Mr. Alvarez' recommendation to develop and present a comprehensive maker vs. buy study and benefit-cost analysis by saying the Company already provided "the qualitative characteristics of a comprehensive make vs. buy analysis" and is "committed to developing a cost benefit analysis for the next rate case."[491] Of course, identifying the "qualitative characteristics" of a study is not the same as undertaking a study. And committing to doing an BCA in the next case is not the same as doing it in this case. Neither is a substitute for comprehensive, independent analyses of whether DTE ratepayers should invest over $100 million for DTE to build a private fiber network versus other communications systems. The rebuttal assertion that satisfying Mr. Alvarez' "level of precision" would "likely require the construction and operation of parallel utility owned and third-party telecommunication systems"[492] is unhelpful exaggeration of the recommended assessments.

The Commission should hold DTE to its order in U-21297 and disallow 2024 and 2025 spending. The Company accepted the risk of proceeding with 2024 spending without a robust analysis of alternatives and a BCA.

1. Other Distribution Operations Capital Issues

i. Tree Trim Risk Prioritization Model

MNSC addressed concerns raised by Mr. Denzler related to ensuring evaluation and audit of DTE's Tree Trim Risk Prioritization model below in the discussion in Section III, **Adjusted**

[491] Hartwick Rebuttal, 4 TR 858-851.

[492] Hartwick Rebuttal, 4 TR 851.

Net Operating Income, under Distribution O&M, related to the Tree Trim Surge, because it is efficiently considered with Mr. Alvarez' recommendation to ensure evaluation and audit to keep the Company on the 5-year trim cycle.

ii. ***Tree Trim Capitalization for Distribution Capital Projects***[493]

Mr. Alvarez addressed the Company's approach to treating tree trimming associated with certain capital programs as capital investments.[494] The Company has capitalized almost $74M of vegetation management spending in 2022 and 2023 alone related to its 4.8kV hardening, 4.8kV conversion, PTMM, and Distribution Automation programs.[495]

MNSC raised this same issue in Case Nos. U-20836 and Case No. U-21297. In U-20836, MNSC witness Ozar testified in opposition to the Company's practice of capitalizing pole and pole top inspections and tree trimming in capital programs.[496] Staff raised concerns about capitalizing pole inspection costs. The ALJ in U-20836 found merit in the issues raised by MNSC and Staff

> [T]he issue identified by [MNSC and Staff witnesses] rise to a sufficiently significant level that the Commission should either require the reporting and stakeholder group that Staff requests, or elevate this matter to the level of an official Commission investigation of the company's accounting. These capital expenditures, increasingly difficult to review in 10-month rate cases, total for distribution and IT system spending alone approximately $1 billion in 2020, with the company's projected test year capital expenditures in these two areas equal to more than $1.5 billion.[497]

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[493] MNSC believes the record related to this topic includes the following:
- Direct Testimony of AG, MEC & NRDC witness Paul Alvarez, 6 TR 3948-52;
- Exs MEC-3, MEC-126;
- Rebuttal Testimony of Theresa M. Uzenski, 6 TR 1575-9.

[494] Alvarez Direct, 6 TR 3948-52.

[495] Ex MEC-3.

[496] Case No. U-20836, Ozar Direct, 8 TR 3999-4016.

[497] Case No. U-20836, September 19, 2022, PFD, p. 719.

The Commission in U-20836 shared the concerns but did not concur in the recommended relief. It stated that it "shares the concerns expressed by the parties to this proceeding about DTE Electric's capitalization accounting procedures and wants to see greater transparency but finds that, in the 10-month rate case timeline, it is not possible to delve as deeply into problematic issues as may be possible through other means."[498] Rather than opening an investigation, the Commission directed DTE in its next rate case to provide a breakdown of pole inspection costs to either support the classification of them as capital or reclassify them to O&M.[499] The Commission also noted its ongoing distribution system spending audit (U-21305) and suggested "more information will be forthcoming" regarding utility capitalization policies.[500]

As a result of the Commission order in U-20836, DTE modified its capitalization practice for pole inspections in U-21297. However, the Commission did not specifically address DTE's practice of capitalizing tree trimming expense in U-20836, and DTE proposed no modifications to its practice in U-21297. So MNSC witness Ozar testified again on the topic, opining that the Company's approach to including trimming in capital is contrary to USOA guidance.[501] The ALJ in U-21297 recognized the issues raised by MNSC in regard to tree trimming but recommended delaying any action pending the distribution audit:

> While this PFD recognizes DTE's incentives to capitalize rather than expense tree trimming, it appears the company's accounting practice has been ongoing for a while. With the impending audit, this PFD concludes that it is preferable to await the audit results. In the meantime, DTE should be reminded that it needs to retain records to establish the legitimacy of its choices.[502]

[498] Case No. U-20836, November 18, 2022, Order, pp. 389, 469-71.

[499] *Id.* at 471.

[500] *Id.*

[501] Case No. U-21297, Ozar Direct, 6 TR 3561-8.

[502] Case No. U-21297, October 5, 2023, PFD, p. 701.

The Commission concurred in and adopted the ALJ's analysis and recommendations.[503]

With the distribution audit still pending and no Commission action yet on this issue, AG-MN witness Alvarez testified in this case again about the impropriety of capitalizing tree trim expense.[504] The USOA Electric Plant Account 365 includes "Tree trimming, initial cost including the cost of permits therefore."[505] Acknowledging this "initial cost" terminology might be ambiguous, Mr. Alvarez referenced USOA Electric Plant Instruction 9, which applies to Account 365, Overhead Conductors and Devices, and states the cost "in connection with the first clearing and grading of land and rights-of-way" is capitalized.[506] Mr. Alvarez corroborated his interpretation – that only first-clearings are capitalized – by reference to the Commission's decision in U-17767 rejecting DTE's proposed capital treatment of enhanced tree trim program costs.[507] Mr. Alvarez testified that "DTE seems to have adopted the policy that if vegetation management is required to complete the work of a capitalized project, the vegetation management spending associated with the project is capitalized as well."[508] He noted that extensive tree trimming had been undertaken under the 4.8kV Hardening, 4.8kV Conversion, PTMM, and Distribution Automation programs and that the amount that the Company is capitalizing annually through these programs was significant and totaled almost $74M for 2022-2023.[509]

Further legitimizing Mr. Alvarez's concerns, DTE in discovery confirmed it has no "comprehensive written policy" in regard to "guid[ing] whether a tree trim expense is capitalized

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[503] Case No. U-21297, December 1, 2023, Order, p. 281.

[504] Alvarez Direct, 6 TR 3948-3952.

[505] See 18 CFR 101.

[506] Alvarez Direct, 6 TR 3949, citing USOA Electric Plant Instruction No. 9.

[507] *Id.* at 6 TR 3950, citing testimony, PFD, and order in Case No. U-17767.

[508] *Id.* at 6 TR 3951.

[509] *Id.*

or expensed," providing at least indirect support for the conclusion that the Company's capitalization policy may be haphazard in practice.[510] What is more, DTE also responded to the same discovery request that "[t]ree trimming to maintain clearances and not tied to a capital project is expensed" as O&M, suggesting the inverse is true – that the Company capitalizes tree trimming to maintain lines prior to capital projects.[511]

Mr. Alvarez recommended the Commission order DTE in its next rate case to identify the extent that it capitalized tree trimming costs in each program, each year, from 2021 through 2024; to present an analysis of the full costs to ratepayers resulting from its decision to capitalize tree trimming costs compared to the cost of on-cycle maintenance O&M trimming; and to explain the legitimacy of its decision to capitalize tree trimming expenses for distribution capital programs.[512]

Company witness Uzenski opposed Mr. Alvarez's recommendations.[513] According to Ms. Uzenski, Mr. Alverez's recommendation is based on a flawed interpretation of the USOA and a misreading of the record and order in U-17767. This brief addresses the USOA and then U-17767.[514]

Ms. Uzenski challenged Mr. Alvarez's interpretation that the USOA supports capitalizing the initial tree trim associated with installing conductor (lines) but not subsequent trims that are done to enable construction work. First, she asserts that Mr. Alvarez ignored the USOA definition of *Maintenance,* which does not include replacement of retirement units.[515] In support, she relies on USOA Operating Expense Instruction 2, *Maintenance.* According to the Company position,

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[510] Ex MEC-126.

[511] *Id*.

[512] *Id.* at 6 TR 3952.

[513] Uzenski Rebuttal, 6 TR 1571-1579.

[514] All references to the USOA are to 18 CFR Part 101.

[515] Uzenski Rebuttal, 6 TR 1576.

since DTE capitalizes trimming related to "installation of new assets (which *do* constitute a retirement unit)," it is proper to capitalize related trimming.[516] In other words, per Ms. Uzenski, replacement of retirement units is not included under Maintenance, and DTE's practice of capitalizing trim related to installation of new assets that are retirement units, so it is consistent with the USOA.

There are four flaws in the Company's logic. The first is the Company makes no case that all capitalized trimming is related to installation of new assets. Moreover, the Company makes no case that any installed "new assets" are "retirement units." In fact, the Company failed to identify what programs or projects are associated with tree trimming that is capitalized, let alone identify the new assets being installed nor that those new assets are "retirement units" under the USOA. DTE has not shown whether replaced crossarms in Hardening or replaced insulators, cutouts, and arresters in PTMM are "retirement units" (as opposed to "minor property").[517] DTE has capitalized almost $74M for 2022-2023 for tree trimming related to its various distribution strategic capital programs.[518] As a result, even accepting the Company's interpretation of the USOA that trimming associated with the replacement of "retirement units" is not *Maintenance* and thus properly capitalized, the Company has not shown that the trimming it capitalizes is all related to replacement of retirement units.

The second flaw in the Company's logic is that it is contrary to the rule of construction that specific language controls over general language. The Company's position ignores the specific provision in the USOA addressing tree trimming associated with overhead distribution lines and

[516] *Id.*

[517] See USAO, Definition, "*Minor items of property* means the associated parts or items of which retirement units are composed"; "*Retirement units* means those items of electric plant which, when retired, with or without replacement, are accounted for by crediting the book cost thereof to the electric plant account in which included."

[518] Alvarez Direct, 6 TR 3951.

instead relies on a broad reading of the general provisions defining *Maintenance*. The USOA defines Account 365 *Overhead Conductors and Devices,* which is the capital account for distribution line assets, to explicitly include "Tree Trimming, initial cost." The Company position disregards this plain language entirely by relying on a general item that is part of Operating Expense Instruction 2 *Maintenance*.

The third flaw is that the Company tries to get too much out of the *Maintenance* instruction. After ignoring the specific provision addressing <u>trimming</u>, the Company pulls from a single item on a list of 8 items in the Operating Expense Instruction 2 *Maintenance:* "Item 8. Replacing or adding minor items of plant which do not constitute a retirement unit. (See electric plant instruction 10)." The Company logic is thus: because it is replacing a retirement unit, that is not "maintenance," and therefore it may capitalize associated trimming. But this part of the USOA does not say or suggest that <u>trimming</u> associated with the replacement of "retirement units" should be capitalized. It says that replacing a retirement unit (per Electric Plant Instruction 10) may not be maintenance. The USOA does not support the Company approach of capitalizing all trimming when it is bundled in a program that may also include some retirement unit replacement.

The fourth flaw is that the Company's interpretation of the USOA is unreasonable. The Company is obligated to maintain its distribution system with adequate vegetation management. The USOA defines Account 593 *Maintenance of Overhead Lines (Major Only)*, which is the maintenance account associated with Account 365 (overhead conductors), to include "Work of the following character on overhead conductors and devices: … k. Trimming trees and clearing brush." Irrespective of whether the Company replaces components after it trims the line, the Company must maintain the lines with adequate trimming and vegetation management. The Commission should decline the Company's invitation to adopt a contorted interpretation of the

USOA. Trimming is maintenance. Packaging trimming with capital replacements does not convert trimming into a capital expense.

The Company's second USOA argument opposing Mr. Alvarez's recommendation is that Mr. Alvarez reads the USOA too narrowly and that the USOA cannot be expected to list every possible type of cost in the description of each account.[519] Ms. Uzenski quotes General Instruction 6 *Item Lists*, which says lists of items are "representative, but not exhaustive." But this is not responsive to Mr. Alvaerez's testimony. Perhaps if the USOA were silent about trimming associated with capital accounts (poles or lines), this argument may be more compelling. But the USOA is very specific about trimming, identifying when it is included in capital (365, lines) and maintenance (593, overhead lines) accounts. The absence of trimming from other capital accounts (*e.g*., 364, poles) appears intentional and meaningful.

The Company's final USOA argument opposing Mr. Alvarez's recommendation relates to the meaning of Electric Plant Instruction 9 *Equipment.*[520] That Instruction says costs of equipment chargeable to electric plant accounts include "costs incurred in connection with the *first clearing* and grading of land and rights of way" (emphasis added). Mr. Alvarez interpreted this Instruction consistent with Account 365, which includes "*initial cost"* of trimming in the capital account. Ms. Uzenski suggests Mr. Alvarez erred by interpreting Instruction 9 to include initial cost of trimming when the term "initial cost" is not included in the Instruction. As quoted by Ms. Uzenski, Electric Plant Instruction 9 provides that costs for the "first clearing" in connection with the costs of equipment may be charged to the capital plan account. It is unclear what else a "first clearing" is, if not the costs associated with the "initial" clearing.

[519] Uzenski Rebuttal, 6 TR 1577.

[520] *Id*.

Also relying on Electric Plant Instruction 9 *Equipment*, Ms. Uzenski asserts that trimming required to install capital assets is "expense incurred by the utility in unloading and placing equipment in readiness to operate."[521] This suffers the same flaws as the "replacement of retirement units" interpretation discussed above. It assumes all capitalized tree trimming is necessary for the "unloading and placing" of equipment, but the Company has not supported that assumption, and instead it seems at least some capitalized trimming is for maintenance programs, particularly the 4.8kV Hardening. Trimming is required to keep lines clear. The Company may coordinate equipment installation to follow trimming, but that does not convert trimming into a capital investment.

The Company's rebuttal related to U-17767 is unavailing.[522] Ms. Uzenski states the Commission in that case did not address tree trim as it relates to the installation or replacement of capital assets, and Mr. Alvarez's testimony is inaccurate and should be rejected. Here again, the Company overstates its own case – it has not shown that all capitalized tree trimming relates to the installation or replacement of capital assets, and in fact it appears that some aspects of the programs where tree trimming is capitalized undertake maintenance and repairs alongside or instead of installation and replacement. And even if the Company coordinates tree trimming with the installation or replacement of capital assets, that does not necessarily convert trimming into a capital investment. The Company must maintain its lines and equipment with adequate vegetation management; if its maintenance program is insufficient such that it requires additional trimming to install or replace equipment or components, that calls into question the adequacy of the maintenance program.

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[521] *Id.*

[522] *Id.* at 6 TR 1578.

Second, Mr. Alvarez did not provide an inaccurate description of the record and order in U-17767. In that case, the Commission rejected the Company argument that the ETTP was effectively a "second initial clearing." Mr. Alvarez accurately quoted Staff's testimony and the Commission order that – consistent with the USOA and Mr. Alvarez's testimony – distinguished between "initial trimming" and subsequent trimming.[523]

The bottom line is that the USOA does not support the Company's position. Mr. Alvarez recommended the Commission take a reasonable approach to ensure ratepayers are not incurring unnecessary and inappropriate capital trimming expenses by ordering DTE in its next rate case to 1) identify the extent that it capitalized tree trimming costs in each program, each year, from 2021 through 2024; 2) present an analysis of the full costs to ratepayers resulting from its decision to capitalize tree trimming costs compared to the cost of on-cycle maintenance O&M trimming; and 3) explain the legitimacy of its decision to capitalize tree trimming expenses for distribution capital programs.[524]

E. EV Charging Forward Capital

1. <u>The Commission should approve DTE's Transportation Electrification Plan with minor modifications and reject the disallowances sought by the Attorney General's office and Commission staff.</u>[525]

MNSC supports DTE's ongoing Charging Forward program and its proposed Transportation Electrification Plan, with minor modifications. DTE's proposals are consistent

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[523] Alvarez Direct, 6 TR 3950.

[524] *Id.,* 6 TR 3951.

[525] MNSC believes the following portions of the record are relevant to these issues:

- Direct and Rebuttal Testimony of DTE witness Pina Bennett, 6 TR 1917-2018;
- Direct and Rebuttal Testimony of MNSC witness Douglas Jester, 6 TR 3782-4041;
- Direct Testimony of Staff witness Alan Freeman, 6 TR 5079-89;
- Direct and Rebuttal Testimony of Staff witness Nicholas Revere, 6 TR 4953-84;
- Direct Testimony of AG witness Sebastian Coppola, 6 TR 3584-3709;

with Commission guidance for utility-funded electric vehicle ("EV") programs, broadly supported by stakeholders and parties, target barriers to EV adoption, and focus on addressing equity by prioritizing investments in low-income and disadvantaged communities.

MNSC recommends the Commission:

- Approve DTE's proposed investments in the Charging Forward and Transportation Electrification Plan, but without specifically endorsing DTE's benefit-cost analysis methodology;
- Reject the recommendations of Staff and AG witnesses urging the Commission to disallow tens of millions of dollars in utility investments, primarily for charging infrastructure in low-income and disadvantaged communities;
- Reject DTE's proposal to subject utility make-ready costs to contribution in aid of construction ("CIAC") paid by customers;
- Require DTE to include specific load profile data in its monitoring and reporting obligations in order to better integrate EV charging into the grid and align EV charging with renewable generation in future proceedings;
- Instruct DTE to prioritize public charging investments to support recipients of federal investments under the National Electric Vehicle Infrastructure and federal grants aimed at transit and school buses.

- Direct and Rebuttal Testimony of MEIU witness Laura Sherman, 6TR 4045-4128;
- Direct and Rebuttal Testimony of EVGo witness Lindsay Stegall, 6 TR 3286-3324;
- Direct and Rebuttal Testimony of Electrify America witness Rhiannon Davis, 6 TR 4762-80;
- Direct Testimony of Electrify America witness Jigar Shah, 6 TR 4781-9;

iii. Overview of DTE's Charging Forward program and its Transportation Electrification Plan

In this proceeding, the Company provides a summary of its previously approved Charging Forward programs and proposes investments of approximately $124.8 million over a four year period, 2025–2028, through a proposed Transportation Electrification Plan.[526] The Charging Forward program, approved in a series of Commission Orders in 2019, 2021, 2022, and 2023,[527] consists of three permanent programs (education and outreach, emerging technology, and program administration) and nine pilots (home charger rebates, home charger installation, EV rebates, business charger rebates, business charger installation, eFleet charger rebates, eFleet battery support, school bus chargers, and charging hubs).[528]

In U-20836, the Commission instructed DTE to "prepare and submit, with its next rate case, a full scale, well-developed, permanent Charging Forward proposal that includes a BCA [benefit-cost analysis]."[529] In response, DTE developed the proposed Transportation Electrification Plan ("Plan"). The goals of the Plan include: "enhance the state's charging network," "break down barriers for low- and moderate-income customers and disadvantaged communities," "integrate EV load with the grid of the future by using advanced technologies to reduce peak demand and minimize costs to all customers," and "deliver reliable, cleaner energy to power EVs and reduce state-wide carbon emissions."[530]

Through the Plan, DTE proposes $124.8 million in investments over the four-year period 2025–2028, primarily serving four customer segments: low-income single family homes, low-

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[526] Bennett Direct, 6 TR 1922,1955, 1967, *see* generally 6 TR 1930-1988.

[527] *Id* at 1922 (*citing* U-20162, U-20935, U-20836, and U-21297).

[528] *Id* at 1930.

[529] *Id* at 1930-1931.

[530] *Id* at 1931-1932.

income multi-unit dwellings, on-route public DCFC charging (with sub-programs in disadvantaged and non-disadvantaged communities), and fleets (broken down into public transit DCFC, school bus DCFC, other DCFC, and other level 2).[531] DTE is not proposing to support workplace charging or destination charging, such as charging at restaurants, shopping centers, or parks. The following chart, from DTE Witness Pina Bennett's Direct Testimony, breaks down the proposed four year program spending in the Transportation Electrification Plan.[532] In the chart below, "segment availability" refers to the percentage of the charger deployments that DTE intends to fund, within each customer segment, that will be needed to support modeled EV adoption in its service territory across the four-year period. For example, in the low-income single family home customer segment, DTE intends to fund 100% of the forecasted charger needs in 2025 through 2028.[533] Within the multi-unit dwelling segment, DTE intends to fund 90% of the charger needs for low-income multi-unit dwellings and 45% of the charging needs at other multi-unit dwellings.[534]

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[531] DTE also proposes $20 million for supporting functions over the four-year period. Bennett Direct, 6 TR 1967.

[532] *Id* at, 1955, 1926.

[533] *Id* at, 1957.

[534] *Id* at, 1959.

Table 9 Proposed TEP Rebate Programs, 2025-2028

Customer Segment	Customer Sub-Segments	Rebate[34]	Segment Availability	Total Investment ($ millions)
SFHs	LI Level 2	$2,200	100%	24.0
MUDs	LI Level 2	$14,400	90%	7.0
	Non-LI Level 2	$5,000	45%	20.7
Public	DAC/rural on-route DCFC	$70,000	35%	21.6
	All other on-route DCFC	$50,000	35%	15.4
Fleet	Transit bus DCFC	$70,000	100%	2.3
	School bus DCFC	$70,000	30%	7.0
	Other DCFC	$70,000	30%	20.0
	Other Level 2	$2,500	90%	6.8
Total	-	-	-	124.8

iv. The Commission should reject the disallowances sought by the Attorney General's office and Commission staff.

Staff witness Allan Freeman asks the Commission to disallow $8 million of DTE's proposed $16 million spending on eFleet and Business Charger rebates, and $1 million of DTE's proposed $3.1 million spending for low-income Residential Customer rebates.[535] Although witness Freeman calls the fleet and business charging investments "foundational," he notes Staff is "uncomfortable" with the level of spending and would prefer a "more deliberate speed" of utility investments.[536] With respect to the low-income residential rebates, while witness Freeman agrees that "the low-income segment faces unique challenges for EV adoption and infrastructure," Staff

[535] Freeman Direct, 6 TR 5080-5091.

[536] *Id* at 5087.

would prefer to see whether the Company's programs "successfully address these challenges" before increasing utility investments to the level of need identified by DTE.[537] Attorney General witness Sebastian Coppola asks the Commission to disallow EV Charging Forward capital expenditures of $7 million in 2024 and $2.3 million in 2025, and utility make-ready investments of $3.7 million in 2024 and $10.2 million in 2025, based on his perception that EV adoption is "currently waning."[538] The Commission should reject each of these recommended disallowances.

First, DTE's benefit-cost analysis, which understates program benefits as described in subsection *iv* below, nonetheless presents a conservative analysis of expected revenues and costs associated with the Transportation Electrification Plan. Even making very conservative assumptions – attributing only 10% of the forecasted EV load (and thus EV charging revenues) through 2030 to the Plan, including zero dollars for societal benefits that come from reduced greenhouse gasses and local smog-forming pollutants, and assuming a constant utilization rate of chargers over time, even as EV adoption grows – DTE found that its Transportation Electrification Plan results in $56 million in rate relief for its customers.[539]

Second, DTE is proposing to defer recovery of rebate spending as a regulatory asset thus eliminating any risk to non-participating customers. As MNSC witness Douglas Jester explained in Rebuttal Testimony regarding witness Freeman's proposals, "there is no effect of the proposed Business and eFleet Charger Rebates" on the rates to be adopted in this matter. For these investments, as well as the low-income residential segment addressed by witness Freeman, if spending on rebates is less than projected, those costs will not be recovered from ratepayers.[540]

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[537] *Id*. at 5088.

[538] Bennett Rebuttal, 6 TR 2000-2001. *See* Coppola Direct, 6 TR 3609.

[539] Bennett Direct, 6 TR 1974.

[540] Jester Rebuttal, 6 TR 4037-4038.

Third, these investments are aimed at addressing the equity gap in EV charging infrastructure by ensuring utility investments deliver benefits to low-income and disadvantaged communities. The Business Charger and eFleet rebates witness Freeman objects to support charging infrastructure across multiple customer segments, including low-income multi-unit dwellings, public on-route DCFC charging in rural and disadvantaged communities, and all fleet segments, including transit and school bus charging. Reducing funding by the requested $8 million would result in 600 fewer rebates for these segments.[541] The low-income residential rebates witness Freeman objects to would average $2,200 to cover the cost of the charger and home installation for low-income customers. Reducing funding by the requested $1 million would result in approximately 455 fewer rebates available to low-income single-family homes.[542] Curtailing investments intended to benefit low-income customers would be contrary to the Plan's goal of "promot[ing] equity by focusing on low-income customers and disadvantaged communities,"[543] and should be rejected by the Commission.

Finally, there is little evidence to support either witness Freeman's or witness Coppola's assertions that the pace EV adoption in DTE's service territory is slowing to such an extent as to justify the Commission reducing utility investments.[544] DTE provides a detailed assessment of EV adoption forecasts in its service territory, anticipated charging needs across all of its supported customer segments, and an estimate of charging infrastructure costs associated with adequately serving the anticipated EV demand through 2028.[545] Witness Freeman offers no support for the

[541] Bennett Rebuttal, 6 TR 2003.

[542] *Id.* at 6 TR 2004.

[543] Bennett Direct, 6 TR 1932.

[544] Freeman Direct, 6 TR 5087.

[545] Bennett Direct, 6 TR 1940-1948.

assertion that the "pace" of EV adoption has slowed,[546] and Coppola's statement that EV adoption is "currently waning" is equally unsupported. As DTE witness Bennett stated in Direct Testimony, EV sales in DTE's service territory have grown at an annual growth rate of 90% per year from 2019 to 2022.[547] Moreover, as Electrify America witness Davis noted, EVs in DTE's service territory are expected to grow from 46,000 today to 326,000 by the end of 2028.[548] As explained by EVGo witness Stegall, Mr. Freeman "does not base his recommendation on any analysis of DTE's customers' needs," and "does not take into account ratepayer benefits."[549] Discovery responses reveal that Mr. Coppola's critique is based on seven news articles, two of which address Tesla's earnings, two relate to the European EV market, and none discuss EVs specific to DTE's service territory.[550] Like Mr. Freeman, Mr. Coppola "does not attempt to connect the various issues he lists to the specific needs of DTE's customers."[551] And, as explained by MEIU witness Laura Sherman, witness Coppola relied on "a limited sample set" of articles collected over a six-month period that fails to establish any kind of long-term trend that should serve as the basis for the Commission's decision.[552] Given the lack of evidentiary support for the assertions made, the Commission should reject the disallowances sought by Staff and AG witness.

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[546] Freeman Direct, 6 TR 5087.

[547] Bennett Direct, 6 TR 1941.

[548] Davis Direct, 6 TR 4768-4769.

[549] Stegall Rebuttal, 6 TR 3314.

[550] *Id.* at 6 TR 3317.

[551] *Id.*

[552] Sherman Rebuttal, 6 TR 4127.

v. The Commission should reject DTE's proposal to eliminate the Contribution in Aid of Construction (CIAC) waiver.

In approving DTE's Transportation Electrification Plan, the Commission should direct the Company to waive Contribution in Aid of Construction (commonly referred to as "CIAC") for all new residential and commercial EV charging infrastructure. Although doing so would continue DTE's practice of waiving CIAC for participants in its Charging Forward programs,[553] DTE has proposed ending the waiver in the Transportation Electrification Plan. The Commission should reject DTE's proposal on this issue and instead instruct the Company to continue to waive these costs in the near term.

As MNSC witness Jester explained in Direct Testimony, DTE's proposal to end the waiver "will create unwarranted inequities and barriers to electric vehicle adoption."[554] Inequities would result from the unequal treatment of customers in nearly identical circumstances, where one unlucky customer would be forced to pay the cost of grid upgrades made necessary by the accumulated EV load of many customers. Under DTE's proposal, those customers who happen to be located in areas where the distribution grid is saturated at the time they want to install an EV charger will be forced to pay for distribution grid upgrades. Customers who are located in areas with surplus distribution capacity, or in an area where a neighbor recently paid to upgrade the grid, will not. Those scenarios could apply to both residential and commercial charging, particularly given DTE's forecasts for widespread EV adoption.[555] Rather than randomly charge some customers for CIAC but not others based on grid conditions wholly outside of their control, MEIU

[553] Jester Direct, 6 TR 3805.

[554] *Id* at 6 TR 3804. Accord Sherman Direct at 48 (Eliminating the CIAC waiver "risk[s] . . . significant inequities and that CIAC will become a barrier to EV adoption.").

[555] Jester Direct, 6 TR 2804-2805.

witness Sherman explains that the most appropriate solution "is to socialize the cost of distribution system upgrades made necessary by the accumulation of EV charging load."[556]

Although CIAC costs are only part of a customer's calculus in deciding to install EV charging equipment, continuing the CIAC waiver would provide clarity and certainty to the private business market at time when EVs are still an emerging technology. DTE estimates that continuing with the waiver would entail ratepayers covering 15% of total capital required for customer connections.[557] But while DTE asserts that "the CIAC waiver played a minimal to non-existent role" in the Charging Forward program,[558] it also claims it needs to end the waiver to further "positive rate impacts."[559] As Electrify America witness Shah explains, "cost certainty is imperative" when making DCFC siting decisions, and "the magnitude of such costs are not often known until very late in the process after significant development work has been committed."[560] This increased business risk for DCFC charging providers "undercuts DTE's goals of expanding public charging infrastructure and reducing range anxiety" and will likely "restrict future DCFC site development."[561]

vi. The Commission should approve the Transportation Electrification Plan without endorsing DTE's benefit-cost analysis.

The Commission should approve DTE's Transportation Electrification Plan, but should do so without endorsing its overly conservative benefit-cost analysis methodology. DTE concludes, even without incorporating the full suite of benefits the Plan will provide, that its proposal would

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[556] Sherman Direct, 6 TR 4095.

[557] Shah Direct, 6 TR 4787.

[558] Bennett Rebuttal, 6 TR 2012.

[559] Bennett Direct, 6 TR 1968.

[560] Shah Direct, 6 TR 4788.

[561] *ID.*

result in $56 million in rate relief for its customers.[562] In its analysis, DTE counts as benefits the payments that customers pay to charge EVs; on the other side of the ledger, it counts as costs any expenditures DTE makes on charging rebates and programs, in supplying power to EV chargers, and in upgrading the distribution grid to accommodate charging needs. By design, DTE's conservative approach: (1) attributes only 10% of EVs in its service territory to its Plan (and thus counts only 10% of electricity sold to charge those EVs as a benefit); (2) assumes a constant utilization rate for chargers, even as EV adoption increases exponentially in subsequent years; (3) fails to include societal benefits of EV adoption spurred by its Plan, including public health benefits of reduced local air pollution, and avoided climate harms from the reduction in greenhouse gas emissions.[563]

DTE's benefit-cost analysis excludes many benefits of its programs, thus understating the value of its Plan, and is better understood as a ratepayer impact analysis. That analysis is useful, and its net positive $56 million rate impact conclusion is more than sufficient for the Commission's approval. But the Commission should not endorse DTE's methodology, as doing so understates the benefits of the Plan and could serve to limit future utility investments. Instead, the Commission should instruct DTE, in future benefit-cost analyses, to include the full suite of benefits from its plan, including the avoided damage from decreased greenhouse gas emissions, public health benefits of reduced air pollution, the avoided customer fuel and maintenance costs from switching to an electric vehicle, among others.[564]

Finally, the Commission should quickly dismiss Staff witness Nicholas Revere's request that the Commission require DTE to prepare site-specific benefit-cost analyses for individual fleet

[562] Bennett Direct, 6 TR 1974.

[563] Sherman Direct, 6 TR 4066-4071.

[564] Jester Direct, 6 TR 3814-3815.

customers and only offer rebates where the individual rebates are net positive for other customers.[565] That kind of customer-specific benefit-cost analysis is unwarranted and inconsistent with the Commission's prior orders. In its November 2022 Order in U-20836, the Commission required DTE to prepare a benefit-cost analysis for a "full scale, well-developed, permanent Charging Forward proposal."[566] The Commission further stated that, "the requirement of a [benefit-cost analysis] should not be interpreted as a requirement that all pilots be financially solvent at the time they are proposed (although that is preferable) but that when weighing costs versus benefits for a full-scale program, benefits outweigh costs over the duration of the program."[567] The Commission should follow the direction it set out in U-20836 and reject witness Revere's request to carve out a new and burdensome benefit-cost requirement applicable only to rebates for DCFC and level 2 charging for fleets.

vii. The Commission should include specific reporting metrics to inform future grid integration proposals to better align EV charging times with renewable energy generation.

DTE proposes to track and report a long list of metrics in its annual Transportation Electrification Plan stakeholder reports, including "rebate applications filed, rebate applications approved, charger uptime, charger utilization rate, on-peak and off-peak charging, customer satisfaction, total investments including equity-focused programs, and installation cost per port, including utility make-ready investment, customer-owed contribution in aid of construction, customer make-ready, and charger costs."[568]

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[565] Revere Direct, 6 TR 4965. Mr. Revere's would apply to DCFC and Level 2 charging for fleets other than transit agencies or schools. Revere Direct, 6 TR 4959.

[566] Case No. U-20836, November 18, 2022, Order, p. 351. Bennett Direct, 6 TR 1969-1970.

[567] *Id.*

[568] Bennett Direct, 6 TR 1968-1969.

The Commission should require DTE to also provide 8760-hour[569] annual load profiles to enable stakeholders to better understand ways to integrate EV charging onto the grid at times of maximum renewable energy generation. Time-of-use rates and managed charging programs can effectively steer charging to off-peak hours, shifting EV charging loads to low-cost, low-demand times of the day, such as at midnight. For the current grid, that is an effective solution. However, as DTE and other utilities in Michigan increase their renewable energy portfolios, the best time of day is likely to evolve to match periods of high wind or solar generation.[570] Requiring DTE to track and report annual load profiles will help the Commission, DTE, and stakeholders achieve two of DTE's express goals for the Plan, which include "integrat[ing] EV load with the grid of the future" and "deliver[ing] reliable, cleaner energy to power EVs."[571]

In response to the proposed metric, DTE offered only that doing so "would be difficult" in certain instances (such as where public chargers are not separately metered), and that DTE had concerns about "data availability, data cleaning efforts, and potential misunderstanding of the data."[572] If the Commission finds that there are, indeed, instances where the data is unavailable, then in those limited use cases DTE should not provide the data. MNSC is not asking for the impossible. The other two excuses (data cleaning and misunderstanding) are well within DTE's powers to resolve, either by effectively "cleaning" data before making it public or by clearly communicating the information contained in the data and any useful conclusions that can be drawn from it. The Commission should not excuse DTE from taking simple measures that would achieve

[569] This is a full year's worth of data: 24 hours in a day x 365 days in a year = 8760 hours per year.

[570] Jester Direct, 6 TR 3806-3809.

[571] Bennett Direct, 6 TR 1932.

[572] Bennett Rebuttal, 6 TR 2004.

two of the Plan's goals while helping the Commission, stakeholders, and DTE prepare for future grid conditions.

The Commission should instruct DTE to prioritize investments and rebates for applicants that have applied for or received federal transportation incentives.In order to better align DTE rebates with federal transportation incentive programs, the Commission should instruct DTE to prioritize Business Charger Rebate and eFleet program applicants that also apply for federal incentives. DTE rebate recipients in these segments enhance charging opportunities for on-route DCFC, transit, and school buses, all of which are also served by federal incentives.

DTE's proposed Plan already recognizes the value of coordinating its programs with federal incentives. For example, the Business Charger and Multi-family programs require rebate recipients to meet uptime standards aligned with the federal National Electric Vehicle Infrastructure ("NEVI") standards.[573] The narrow, specific direction sought from the Commission here would improve that coordination in meaningful ways. First, DTE's Business Charger rebates provide support for on-route DCFC charging for the same market segment served by the federal NEVI funding. Under the NEVI program, designed to provide a baseline of high-speed charging along interstate highways, Michigan will receive $110 million in incentives over five years (2022–2026).[574] Although NEVI provides up to 80% of the project costs, NEVI funds typically do not cover grid upgrades, and federal guidance encourages states to "explore whether they could be covered by electric utilities . . . so as to minimize use of NEVI funds for grid upgrades wherever possible."[575] For this customer segment, DTE should prioritize funding Business Charger rebate

[573] Jester Direct, 6 TR 3809-3810.

[574] Federal Highway Administration, 5-year National Electric Vehicle Infrastructure Funding By State, https://www.fhwa.dot.gov/bipartisan-infrastructure-law/evs_5year_nevi_funding_by_state.cfm.

[575] Jester Direct, 6 TR 3810.

recipients that apply for NEVI funding, which is consistent with the Commission's directive in U-21297 "requiring [the Business Charger rebate] program be coordinated with NEVI as . . . that may enhance the program's goals."[576]

Second, DTE's eFleet charger rebates for schools and transit buses should prioritize applicants that also apply for federal programs for zero emission buses, such as the Environmental Protection Agency's Clean School Bus program and the Federal Transit Administration's Low or No Emissions grant program for transit buses.[577] By pairing utility rebates with federal incentives, DTE could expand the reach of ratepayer-funded investments, increase EV adoption in its service territory, and better serve its customers.

F. EV Rebates (Reserved)

G. LED Capital (Reserved)

H. Lighting Underground Cable (Reserved)

I. Demand Response Portfolio (Reserved)

J. IT Capital (Reserved)

K. IT Customer Service Capital (Reserved)

L. Energy Supply Capital (Reserved)

M. Nuclear Capital Expenditures (Reserved)

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[576] Case No. U-21297, December 1, 2023, Order, p. 266. Accord Jester Direct, 6 TR 3811.

[577] Jester Direct, 6 TR 3811.

III. COST OF CAPITAL

N. A. Return on Equity: The Commission should approve an ROE of 9.3%.[578]

The criteria for establishing a fair ROE for public utilities derive from the famous *Bluefield* and *Hope* U.S. Supreme Court cases.[579] In *Bluefield,* the U.S. Supreme Court explained that a "public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties…"[580] However, a utility "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."[581] In *Hope*, the Court explained that "the ratemaking process involves a balancing of the investor and the consumer interests."[582]

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[578] MNSC believes the following is the record on this issue:

- Direct and rebuttal testimony of DTE witness Bente Villadsen, 6 TR 2401-2540;
- Ex A-14, Schedules D5 through D5.19 and Ex A-39, Schedules DD1 through DD12.
- Ufolla Direct, 6 TR 5005-26;
- Coppola Direct, 6 TR 3657-83;
- Exs AG-1 to -AG-48;
- Walters Direct and Rebuttal, 6 TR 3422-3504;
- Exs AB-4 to AB-18;
- Bandyk Direct, 6 TR 3741-62;
- Exs CUB-2 to CUB-10.
- Perry Direct, 2 TR 4718-34;
- Exs WAL-1 to WAL-4 and
- Stults Direct, 6 TR 4252-56;
- Exs AA-15 to AA-35.

[579] *Bluefield Waterworks & Improvement Co v Pub Serv Comm of West Virginia*, 262 US 679; 679 (1923) and *Fed Power Comm v Hope Natural Gas Co*, 320 US 591 (1944).

[580] *Bluefield,* 262 US at 692-93.

[581] *Id*.

[582] *Hope,* 320 US at 603.

The Michigan Supreme Court has held that the MPSC is not bound by any particular method or formula in determining just and reasonable rates.[583] "What is important is whether the result reached is just and reasonable."[584] The Commission can "make the pragmatic adjustments which may be called for by particular circumstances."[585]

In this section, CUB-MEC do not attempt to cover the entire field of evidence and arguments concerning ROE in this case. CUB trusts Staff, ABATE, and the Attorney General will do that. Rather, what follows highlight points and perspectives of importance to CUB and MEC in their consumer advocate roles.

DTE Electric currently has an authorized return on equity (ROE) of 9.90%.[586] DTE witness Dr. Bente Villadsen proposes that the Commission increase this ROE by 60 basis points, to 10.50%.[587] That request is an untenable overreach, and witnesses for Staff, the Attorney General, ABATE, CUB-MEC, Walmart, and Ann Arbor all oppose it. The parties' proposed ROEs can be summarized as follows:

Party	Witness	ROE
Staff	Ufolla	9.90%[588]
Attorney General	Coppola	9.85%[589]
ABATE	Walters	9.60%[590]
CUB-MEC	Bandyk	9.30%[591]

[583] *Building Owners & Managers Ass'n of Metropolitan Detroit v Public Service Comm,* 424 Mich 494, 510 (1986).

[584] *ABATE v Public Service Comm,* 208 Mich App 248, 266 (1994).

[585] *ABATE, supra* at 266-67, citing *Michigan Bell Telephone Co v Public Service Comm,* 332 Mich 7, 36 (1952).

[586] Case No. U-21297, December 9, 2021, Order, p. 93.

[587] Villadsen Direct, 6 TR 2446.

[588] Ufolla Direct, 6 TR 5013.

[589] Coppola Direct, 6 TR 3683.

[590] Walters Direct, 6 TR 3423.

[591] Bandyk Direct, 6 TR 3761.

Recognizing that CUB-MEC's recommendation is at the low end of this range, CUB-MEC maintains that Mr. Bandyk accurately analyzed DTE Electric's market-based cost of equity and provides compelling support for the Commission to reduce the company's rich ROE. The Commission should deny DTE's request to increase its authorized ROE, and should instead lower the Company's ROE to 9.30% or somewhere between that figure and the current authorized figure of 9.90%, for the reasons that follow.

1. <u>DTE Electric's authorized ROE should be aligned with the market cost of equity, which it currently is not.</u>

On behalf of CUB and MEC, witness Bandyk discussed evidence documenting that public regulatory commissions tend to set electric utility ROEs above the market cost of equity, resulting in detrimental wealth transfer from ratepayers to shareholders.[592] One analysis showed that costs to consumers from rates of return for electric and gas utilities that are set above a market-based rate reached around \$2-\$20 billion per year by 2020.[593] This premium is an unjustified cost imposed on customers.[594] A higher return implies higher risk, so the fact that awarded ROEs are higher than market returns would imply that regulated utilities are riskier investments than the market as a whole – but that is plainly not the case.[595] Utility holding company betas tend to be less than one, meaning that those stocks are less sensitive to changes in overall market returns.[596]

In Consumers Energy's last electric rate case, Case No. U-21389, the ALJ found merit in Mr. Bandyk's positions that average awarded ROEs for public utilities have been above the

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[592] *Id.* at 3744.

[593] *Id.* at 3745.

[594] *Id.*

[595] *Id.* at 3746.

[596] *Id.*

market.[597] The ALJ also found merit in Mr. Bandyk's position that utility holding company betas have been less than one and therefore less risky than the market as a whole.[598] Also in the last DTE Gas rate case, Case No. U-21291, the ALJ agreed with Mr. Bandyk: "that regulated utilities are much less risky than other businesses is without question … . [P]ublic utilities like DTE have a captive customer base to which it sells necessary services (heat and power) while operating as a monopoly insulated from any competition from alternative vendors."[599] The ALJ also pointed out that "it is axiomatic that under the Supreme Court standards a regulated utility's authorized return must be less than the return being earned by the general market," and that evidence in that case showed that the average of recently-authorized ROEs exceed recent historical returns for the general market.[600]

Mr. Bandyk posits that regulators tend to set ROEs higher than the commensurate level of risk for electric utilities because regulators tend to accept estimates of ROE that are above fair, market-based ROE estimates.[601] In this case, DTE proposes an ROE of 10.50%, a significant increase from the 9.90% ROE authorized in Case No. U-21297.[602] At that figure, DTE would collect **$1.31 billion** from customers just for return on rate base.[603] By contrast, at Mr. Bandyk's recommended 9.30% figure, DTE would collect $1.2 billion for return on rate base – a savings to customers of $104 million on an annualized basis.[604]

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597 Case No. U-21389, December 21, 2023, PFD, pp. 357-358.

598 *Id*. at 360.

599 Case No. U-21291, September 4, 2024, PFD, pp. 214-15 (quoting and discussing S&P; Case No. U-20836, Nov. 18, 2022, Order, p. 231, 241; September 19, 2022, PFD, p. 449-450, 8 TR 3065; *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19, 48-49 (1909); and *Bluefield,* 262 U.S. at 693).

600 *Id.* at 216.

601 *Id* at 6 TR 3746.

602 *Id*.

603 *Id*. at 6 TR 9.

604 *Id.* at 6 TR 3748.

DTE witness Villadsen testified in rebuttal in regard to the ROE recommendation of Mr. Bandyk that it is "is below that allowed for any integrated electric utility in 2024 except Public Service New Mexico, which is a unique decision that is under appeal at the New Mexico Supreme Court. The recommendation is also well below that of other Staff and Intervenor witnesses indicating that he relies on outlier inputs or models."[605] Given the academic research Mr. Bandyk submitted and summarized in his testimony shows that regulatory commissions around the country have empirically authorized returns on equity above a market-based cost of equity, however, it is not surprising that Mr. Bandyk's recommendation for ROE, which strives to estimate a market-based cost of equity, is lower than that of authorized returns.

DTE witness Villadsen also testified in rebuttal in regard to the ROE recommendation of Mr. Bandyk that "DTE Electric is of higher risk than the sample companies"[606] in part because "the fact that DTE Electric has a slightly lower industrial load, [and] the Michigan load is relatively concentrated in the automotive sector and thus susceptible to changes in one industry."[607] Dr. Villadsen provides no evidence, however, that the Michigan load is more concentrated than that of the industrial load for proxy group companies, or that if it is more concentrated, that level of concentration produces more risk to compensate for the lower amount of industrial load in DTE's service territory compared to the proxy group companies.

DTE witness Villadsen further testified in rebuttal in regard to the ROE recommendation of Mr. Bandyk that "Michigan saw a larger increase in unemployment during COVID-19 than did the U.S. on average. These facts indicate that the industrial load is relatively concentrated and could be volatile. I therefore do not believe that a 2 percent lower than average industrial load

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[605] Villadsen Rebuttal, 6 TR 2497.

[606] *Id.* at 2533.

[607] *Id.* at 2534.

materially impacts DTE Electric's business risk relative to the comparable companies."[608] Dr. Villadsen's argument is not convincing, however, because the question is not how Michigan compares to the U.S. on average, but how DTE's service territory compares to those of the proxy group companies. Again, Dr. Villadsen does not consider that the industrial load for proxy group companies might also be relatively concentrated.

2. Capital Asset Pricing Model (CAPM) analysis.

DTE witness Villadsen testified that the CAPM assumes that the returns investors expect to receive are commensurate with the risk of those assets relative to the market as a whole.[609] The CAPM states that the cost of capital for an investment is determined by the risk-free rate plus the stock's systematic risk (as measured by beta) multiplied by the market risk premium.[610] The parties' CAPM results are as follows:

Party	Witness	CAPM
DTE	Villadsen	10.9% to 11.7%[611]
ABATE	Walters	8.6 to 10.37%[612]
Attorney General	Coppola	10.57%[613]
Staff	Ufolla	10.23% - 10.31%[614]
CUB-MEC	Bandyk	8.53%[615]

CUB-MEC witness Bandyk testified that Dr. Villadsen's CAPM estimate is inflated by her choice of equity risk premium (ERP).[616] Dr. Villadsen used an ERP of 7.17% ERP as the historical

[608] *Id*.

[609] Villadsen Direct, 6 TR 2474.

[610] *Id*. at 2474-5.

[611] Villadsen Direct, 6 TR 2436.

[612] Walters Direct, 6 TR 3477.

[613] Coppola Direct, 6 TR 3671.

[614] Ufolla Direct, 6 5021

[615] Bandyk Direct, 6 TR 3749.

[616] *Id* at 3752.

average premium of market returns over the income returns on government bonds from 1926 to 2022. Mr. Bandyk stated that this methodology has two flaws: the historical estimate for ERP is sensitive to the historical time period selected[617] and "historical estimates of ERP are subject to the problem of survivorship bias, where returns that go into historical ERPs tend to be those from stocks that remain in the market, rather than those that drop out" – which inflates historical ERPs.[618] To correct these flaws, Mr. Bandyk used an implied equity risk premium. [619]

CUB-MEC witness Bandyk also testified that Dr. Villadsen's CAPM estimate is further inflated by her choice of how she calculated the beta variable used in the CAPM formula.[620] He testified that book values of equity should be avoided because they were based on accounting principles and, instead, market values of equity should be employed to calculate beta because they more closely reflected investor perceptions.[621] Mr. Bandyk explained that Dr. Villadsen properly used the market value of equity when she was un-levering the proxy company betas to arrive at asset betas for those companies. [622] When she re-levered the average asset beta group, however, she used DTE's book value equity, which Mr. Bandyk stated results in a "beta that is not only inconsistent with the Hamada adjustment theory and unable to be interpreted as a representation of the company's risk vis-à-vis the market, but also is inflated compared to what the beta would be if the market value of equity was used in the adjustment."[623]

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[617] *Id.* at 3753.

[618] *Id*.

[619] *Id*. at 3754; results presented in Ex CUB-6.

[620] *Id.* at 3756.

[621] *Id.*

[622] *Id*. at 3757.

[623] *Id.*, internal footnote omitted.

DTE witness Villadsen testified in rebuttal that Mr. Bandyk's use of Kroll as a data source was in error in determining the market equity risk premium (MRP) and risk-free premium numbers employed in the CAPM model. [624] Mr. Bandyk separately averaged the values provided by Kroll and two other data sources to calculate the MRP and risk-free premium values.[625] In other words, values on MRP from three data sources (including Kroll) were averaged together to generate the MRP to use in the CAPM model. And three separate numbers in regard to risk-free premium values (including one from Kroll) were averaged together to generate the separate risk-free premium value to also be used in the CAPM model. Dr. Villadsen stated that "Mr. Bandyk uses the recommended MRP from Kroll, but fails to acknowledge that Kroll states that this MRP should be used with the higher of the current risk-free rate and that recommended by Kroll."[626] Even if Mr. Bandyk used the 20-year U.S. Treasury yield (4.57%) as the proxy for the risk-free rate instead of 3.5% as the risk-free rate, as Dr. Villadsen suggests,[627] the impact is inconsequential. The average of the 3 risk-free rates in Mr. Bandyk's CAPM analysis would be 4.35% versus 4.0%.[628] And the CAPM would be 8.88% versus 8.53%.[629]

[624] Villadsen Rebuttal, 6 TR 2510

[625] Bandyk Direct, 6 TR 3754.

[626] Villadsen Rebuttal, 6 TR 2509-10.

[627] Villadsen Rebuttal, 6 TR 2510.

[628] Ex CUB-6 ((4.40 + 4.1 + 4.57)/3 = 4.35%).

[629] See Ex CUB-8 (where b) Risk Free Rate is 4.35 then b + (a*c) = 4.35 + (4.87 * 0.93) = 8.88)).

Dr. Villadsen also testified in rebuttal that "Mr. Bandyk relies on *Kroll's* normalized MRP of 5.0 percent, but he fails to mention that the normalized MRP is derived using *historic* data. This is completely contradictory to the arguments he levies against my historic MRP values."[630] Dr. Villadsen provides no specific evidence to support her argument regarding Kroll's alleged methodology. Kroll describes its methodology in developing its MRP and risk-free rate as being based on current (not historic) market conditions: "*Based on current economic and financial market conditions*, the Kroll Recommended ERP is being lowered from 5.5% to 5.0% when developing USD-denominated discount rates as of June 5, 2024, and thereafter, until further notice. In addition, we continue to recommend using the spot 20-year U.S. Treasury yield as the proxy for the risk-free rate if the prevailing spot yield as of the valuation date is higher than the Kroll normalized U.S. risk-free rate of 3.5%."[631] In discovery, Dr. Villadsen provided the support for her assertion that the normalized MRP "is derived using *historic* data," but that presentation shows Kroll's considers "historical ERP estimates" plus forward-looking estimates in assessing the range of unconditional ERP.[632] Kroll's recommendation to lower its recommended U.S. ERP from 6.0 to 5.5% is based on current market conditions.[633]

Dr. Villadsen also testified in rebuttal that "I disagree with his statement that there are 'methodological problems that come with extrapolating a forward ERP from historic data. For example, the widely used MBA text of Brealey, Myers and Allen (2017) uses the historical average market risk premium in their examples, the text of Ross, Westerfield and Jaffe (2012) notes that

[630] Villadsen Rebuttal, 6 TR 2510, emphasis original.

[631] Kroll, "Kroll Lowers its Recommended U.S. Equity Risk Premium to 5.0%, Effective June 5, 2024," June 6, 2024, page 2, emphasis added.

[632] Ex MEC-122, p. 5.

[633] Kroll, "Kroll Lowers its Recommended U.S. Equity Risk Premium to 5.0%, Effective June 5, 2024," June 6, 2024, page 2-4 (describing recent trends in economic indicators and financial markets).

‘We [the 3 authors] are comfortable with an estimate based on the historical U.S. equity risk premium of about 7 percent…’”[634] Neither of these sources, however, that Dr. Villadsen contends dispute the methodological problems with the historic ERP actually address the problems of the biased time period and survivorship bias that are mentioned in the testimony of Mr. Bandyk.[635] Dr. Villadsen appears to assume that because these the Brealey and Ross texts mention the historic ERPs as examples that means those authors do not agree with those methodological problems. That assumption does not follow from the texts she cites. In other words, citing the application of the historic ERP as an example does not mean the author endorses the use of the method in a utility rate case. The Brealey text discusses how one might consider historic returns if one wanted to gain insight from historical returns (when it is appropriate to use arithmetic averages or compound annual returns) – the text does not endorse Dr. Villadsen’s approach.[636] The Ross text similarly addresses the U.S. ERP in light of historical international context.[637]

3. The Commission has consistently rejected use of the Empirical CAPM (ECAPM).

DTE witness Villadsen also used the ECAPM model.[638] She asserted that the “CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums

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[634] Villadsen Rebuttal, 6 TR 2512-3.

[635] Ex MEC-124 (cited sources).

[636] Ex MEC-124, pp. 3-6.

[637] Ex MEC-124, pp. 8-11.

[638] Villadsen Direct, 6 TR 2518.

than predicted."[639] The ECAPM makes an adjustment to the risk-return calculation in the CAPM to account for this claimed deficiency.[640]

ABATE witness Walters explained the technical flaws with the ECAPM and with Dr. Villadsen's application of it.[641] CUB-MEC witness Bandyk stated that ECAPM is "not a widely accepted method as part of ROE analyses in rate cases."[642] Additionally, the ALJ in Consumers Energy's last electric rate case found that the ECAPM is a controversial and unnecessary model that neither the MPSC nor FERC accept:

> This PFD notes that Consumers has not identified an order wherein the Commission has recognized let alone adopted the use of the ECAPM model, and this ALJ is unaware of any. In addition, the [PFD] notes that the FERC does not recognize the use of ECAPM, which it considers to be an "obscure" and "more controversial" variant of CAPM. More significantly, this PFD notes that the Commission "has consistently taken a traditional approach" to establishing ROE, focusing on the "most commonly used, fundamental approaches" to determining a just and reasonable ROE. Accordingly, this PFD finds that Consumers' ECAPM estimates should not be considered.[643]

The ALJ in Case No. U-21291 similarly concluded "ECAPM estimates should not be considered" for similar reasons.[644] There is no basis to reach a different conclusion in this case.

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639 *Id*.

640 *Id*.

641 Walters Direct, 6 TR 3482.

642 Bandyk Direct, 6 TR 3755.

643 Case No. U-21389, Dec. 21, 2023, PFD, pp. 337-338.

644 Case No. U-21291, Sept. 4, 2024, PFD, p. 204.

4. Discounted Cash Flow (DCF) analysis.

DTE witness Villadsen explained that the DCF model "assumes that the current market price of a stock is equal to the present value of the dividends that its owners expect to receive [where the] expected stream of future dividends is discounted at a risk-appropriate rate to arrive at the present value of the dividends, represented by the current stock price."[645] Dr. Villadsen applied both simple-stage and multi-stage DCF models, while expressing a preference for the simple-stage version.[646] The parties' DCF results are as follows:

Party	**Witness**	**DCF**
DTE	Villadsen	10.0% to 11.0%[647]
ABATE	Walters	8.83 to 10.51%[648]
Attorney General	Coppola	9.26%[649]
Staff	Ufolla	9.71% to 9.78%[650]
CUB	Bandyk	8.66%[651]

[645] Villadsen Direct, 6 TR 2437.

[646] *Id.* at 2439.

[647] *Id.*

[648] Walters Direct, 6 TR 3459.

[649] Coppola Direct, 6 TR 3664.

[650] Ufolla Direct, 6 TR 5026.

[651] Bandyk Direct, 6 TR 3749.

CUB-MEC witness Bandyk testified witness Villadsen made a similar error with her multi-stage DCF model as she made with her CAPM model.[652] Namely, Mr. Bandyk stated that Dr. Villadsen adjusted her model to account for the differing amount of debt in the capital structures of the proxy group companies by using the book value of equity for DTE's capital structure, as opposed to employing the market value of that equity.[653] Mr. Bandyk testified that "this choice of equity value leads to an inflated result because of the difference between book value equity and market value equity."[654]

CUB-MEC witness Bandyk also testified that that DTE witness Villadsen's DCF simple stage model should not be used for estimating utility ROEs because it only uses a five-year growth rate for earnings.[655] The result is that the utility's rate of earnings growth is higher than the economy as a whole – such that in the long run, the utility would grow bigger than the entire U.S. economy.[656] ABATE witness Walters criticized Dr. Villadsen's use of the simple-stage DCF model on similar grounds, explaining that "[u]tilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services.[657]

In rebuttal, Dr. Villadsen noted that Mr. Bandyk used the multi-stage model but not a single-stage and suggests "he ought to use an average of the single-stage and multistage models."[658] This suggestion – without addressing the flaws in the single-stage method or explaining why he should have used both and averaged them – is unavailing and unpersuasive.

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[652] *Id*, at 3757.

[653] *Id,* at 3758.

[654] *Id.*

[655] *Id*, at 3759.

[656] *Id*.

[657] Walters Direct, 6 TR 3455.

[658] Villadsen Rebuttal, 6 TR 2506.

5. The Risk Premium Model should not be used at all.

Dr. Villadsen explained that in the risk premium model, the cost of equity capital for utilities is estimated based on the historical relationship between allowed ROEs in utility rate cases and the risk-free rate of interest at the time the ROEs were granted."[659] The method adds "a 'risk premium' implied by this relationship to the relevant (prevailing or forecast) risk-free interest rate.[660]

CUB-MEC witness Bandyk testified that the risk premium method should not be used to set utility ROEs. The method "introduces into the calculation of ROE, a process that should be based on objective data as much as possible, the reliance on ROEs set by other regulatory commissions" – which he previously explained are already above the market.[661] FERC rejected the methodology in Opinion 569 after finding various disadvantages with it.[662]

Consistently, the ALJ in DTE Electric Company's last concluded rate case, U-21297, rejected Dr. Villadsen's use of the risk premium analysis, finding: "[t]his PFD also finds that the approach of performing a risk premium analysis based on a regression of the returns awarded by regulatory commissions relative to the treasury interest rate is not a compelling analysis, and should be rejected for the reasons explained by [Attorney General witness] Coppola…"[663] In the testimony the ALJ referenced, Mr. Coppola had explained that the risk premium method falsely assumes "that treasury bond yields are the primary driver in ROE decisions by regulators;" that

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[659] Villadsen Direct, 6 TR 2440.

[660] *Id*.

[661] Bandyk Direct, 6 TR 3760.

[662] FERC Opinion 569, 169 FERC 61129 (2019), par. 341.

[663] Case No. U-21297, PFD, October 5, 2023, p. 484.

the method is "not connected to stock market performance and investor expectations of returns on investment;" and that utility commissions often base ROE decisions on "gradualism."[664]

However, since then, as Dr. Villadsen and the ALJ in Case No. U-21291 point out, FERC changed course in Opinion 569-A, but that decision was remanded to FERC on the basis Opinion 569-A failed to explain why it changed course "after initially, and forcefully, rejecting it."[665] The ALJ found Mr. Bandyk's opposition and the reasoning in the original FERC Opinion 569 persuasive but found it premature to reject the model entirely, though it did not materially impact the various results.

6. For the reasons discussed by Mr. Bandyk and in the original FERC Opinion 569, CUB and MEC maintain the Risk Premium Model is unhelpful.

In light of the above discussion, CUB respectfully requests that the Commission set DTE Gas Company's authorized ROE at 9.3%; or such other level that balances the interests of the utility and its customers and produces a result that is just and reasonable.

B. Overall Rate of Return: The Commission should approve an overall rate of return of 5.45%.

Based on a ROE of 9.3%, CUB witness Bandyk recommended an overall rate of return of 5.45% as a result of this ROE (see Exhibit CUB-9).[666]

[664] Case No. U-21297, Coppola Direct, 6 Tr 3750, PFD, p. 484.

[665] Villadsen Rebuttal, 6 TR 2429-30; Case No. U-21291, September 4, 2024, PFD, pp. 208-209 (quoting *MISO Transmission Owners v. FERC*, 45 F.4th 248, 263, 264 (CA DC Cir. 2022)).

[666] Bandyk Direct, 6 TR 3748; Ex. CUB-5.

C. Capital Structure (Reserved)

D. ST Borrowing Rates (Reserved)

E. LT Borrowing Rates (Reserved)

IV. ADJUSTED NET OPERATING INCOME

A. Depreciation and Amortization (Reserved)

B. Property Tax (Reserved)

C. Inflation Rates: The Commission should make a productivity adjustment to DTE's projected inflation rate, or alternatively should adopt the inflation rate proposed by ABATE or the Attorney General.[667]

DTE projects O&M expense in the projected test year to increase by $42.5 million, or about 3.5%, relative to the 2022 historical level.[668] A key driver of this increase is DTE's projected inflation rate.[669] DTE applied historical non-labor inflation rates of 4.1% in 2023, 2.4% in 2024; and projects inflation of 2.2% for 2025.[670] The Company also applied a 3% annual inflation factor to non-contract labor and contract labor from 2023 to 2025.[671]

CUB-MEC witness Matthew Bandyk testified that "[w]hile it is prudent to expect that costs will be affected by inflation, it is also prudent to factor in how productivity gains may mitigate

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[667] MNSC believes that the following portions of the record are relevant to these issues:

- Direct Testimony of DTE witness Theresa Uzenski, 6 TR 1496-97.
- Ex A-13, Schedule C5.
- Direct Testimony of CUB-MEC witness Matthew Bandyk, 6 TR 3741-42.
- Ex CUB-2, CUB-3, and MEC-27.
- Direct Testimony of ABATE witness Jessica York, 6 TR 3335-3342.
- Ex AB-1.
- Direct Testimony of AG witness Sebastian Coppola, 6 TR 3684-86.
- Rebuttal Testimony of DTE witness Neal Foley, 2 TR 176-77.

[668] York Direct, 6 TR 3335.

[669] *Id*.

[670] Bandyk Direct, 6 TR 3741; Exhibit A-13, Schedule C5.15, row 9.

[671] *Id*., citing rows 1 and 5 of the exhibit.

inflation;" and DTE "does not make any adjustment for productivity."[672] Mr. Bandyk stated that it is "reasonable to expect that a business will, on average, make some productivity gains year to year;" and Bureau of Labor Statistics (BLS) data document those gains.[673] These data show an average annual private nonfarm sector productivity factor change of 0.61% from 2013 to 2023, and a higher average change of 0.70% for Michigan.[674]

Mr. Bandyk stated that "[a]s a regulated utility, DTE does not face the competitive pressures to improve productivity that can be found in non-regulated industries. Therefore, if DTE customers are going to benefit from the cost savings, a productivity factor should be applied to reduce the utility's projected costs when calculating its revenue requirement. Doing so would simulate the effect of productivity improvements on DTE's costs."[675] He noted that the "data from Exhibits CUB-2 and CUB-3 represent conservative estimates for the basic productivity improvements that have been empirically achieved in the private sector in recent history."[676] He recommended that the Commission apply the national productivity factor of 0.61% to reduce DTE's Non-Labor inflation rates of 4.1% for 2023, 2.4% for 2024, and 2.2% for 2025.[677] He also recommended that the Commission apply the Michigan productivity factor of 0.70% to reduce the 3% inflation factors for both Labor and Contractor Inflation, for the same years.[678]

ABATE witness Jessica York presents data that provides independent – if unintentional – corroboration for Mr. Bandyk's position that productivity gains partially offset cost increases due

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[672] *Id*.

[673] *Id*.

[674] Bandyk Direct, 6 TR 3741-2; Exs CUB-2 (national) and CUB-3 (Michigan).

[675] Bandyk Direct, 6 TR 3742.

[676] *Id*.

[677] *Id*.

[678] *Id*.

to inflation. Ms. York testified that DTE's projected O&M expense for 2023 exceeded its actual O&M expense for that year by $56.4 million.[679] She also testified that DTE's projected O&M expense increases for 2024 and 2025 "significantly exceed the actual average annual increase in O&M expense experienced by DTE over the last several years."[680]

In rebuttal, DTE witness Neal Foley disagreed with witness Bandyk's recommendation to reduce the Company's proposed inflation rates to account for productivity gains.[681] Mr. Foley stated that DTE's "known and measurable cost reductions related to productivity gains would be embedded in each business unit's financial exhibits."[682] Therefore, he reasoned, "adjusting the Company's inflation rates downward to account for potential productivity gains when productivity gains are already embedded in each business unit's financial exhibits would represent a 'double counting' of productivity improvements."[683] However, when asked in discovery to identify those productivity gains he described, Mr. Foley stated that DTE does not track them, cannot identify them, and has no methodology for measuring them.[684]

Mr. Foley also argued that applying a productivity factor "conflicts with the 'known and measurable' nature of forward test year projections."[685] Instead, he asserted, "the current approach to embedding productivity gains into each business unit's financial exhibits based on what is achievable by the forward test year is more appropriate."[686] But that claim is inapposite to the topic at hand. DTE applies general inflation rates to project a general increase in its O&M expense. The

[679] York Direct, 6 TR 3335-6.

[680] *Id*. at 3337.

[681] Foley Rebuttal, 2 TR 177.

[682] *Id*.

[683] *Id*.

[684] Ex MEC-27, discovery responses MNSCDE-18.5a-c.

[685] Foley Rebuttal, 2 TR 177.

[686] Foley Rebuttal, 2 TR 177-8.

Company does not take all of the known and measurable changes to each business unit's expenses and sum them up into a general inflation rate. If DTE can apply a general upward adjustment to its total O&M expenses to account for inflation rates, it can and should apply a general downward adjustment to the general inflation rates to represent a partial offset for productivity gains. The Commission should therefore adopt Mr. Bandyk's productivity adjustments to DTE's inflation rates.

In the alternative, if the Commission does not adopt the productivity adjustment to inflation rates, the Commission should adopt the inflation rates presented by ABATE or the Attorney General.

D. Distribution O&M –Tree Trim Surge and Risk Model Audits are Necessary[687]

The Company is proceeding towards the completion of the transition to the ETTP program, with the goal of being 100% on-cycle by the end of 2025.[688] AG-MN witness testified regarding the potential to backslide on vegetation management and the importance of imposing regulatory guardrails to ensure tree trimming remains on cycle.[689] To that end, he made two recommendations: (1) continue the tree trim public report filed annually in U-20162, which has proven valuable to support transparency and accountability; and (2) initiate period third-party audits of DTE overhead right of ways. He offered eight reasons for an audit: (1) trimming drives reliability; (2) DTE is incentivized by earnings potential to defer trimming once the Surge is over;

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[687] MNSC believes the following is the relevant record:

- Direct Testimony of DTE witness Rachel L. Steudle, 6 TR 2986-91; Rebuttal Testimony of Ms. Steudle, 6 TR 3019-25;
- Direct Testimony of AG witness Sebastian Coppola, 6 TR 3688-9;
- Ex AG-40;
- Direct Testimony of AG, MEC & NRDC witness Paul Alvarez, 6 TR 3956-58.

[688] Steudle Direct, 6 TR 2986-91.

[689] Alvarez Direct, 6 TR 3956-8.

(3) DTE historically deferred trimming; (4) deferral is not obvious until reliability deteriorates, which lags deferral; (5) interveners cannot readily detect deferral; (6) variable compliance with trim standards can mask trim deferral; (7) trimming with capital programs makes it difficult to track routine clearing; and (8) DTE is proposing program modifications, which should be evaluated against routine trimming. Mr. Alvarez recommended an independent audit immediately after the Company is on cycle for ETTP (2025 or 2026) to serve as a baseline, then an inspection audit every five years.[690]

Company witness Steudle supported continued filing of the annual tree trim report but opposed the recommendation for an independent audit of Company right-of-ways every five years because it would be redundant of and less cost-effective than other trim cycle compliance monitoring.[691] The rebuttal notes the Company already performs inspection audits of miles trimmed to ensure compliance with clearances, cross referencing direct testimony.[692]

MNSC appreciates the Company will continue to file annual tree trim reports but maintains that an independent audit of compliance with the trim cycle is critical, for the reasons Mr. Alvarez identified. Auditing to ensuring DTE remains on cycle is not redundant of Company post-clearing inspection audits, which ensure the trim was to standard. The Commission holding DTE to a 5-year trim cycle is different than DTE holding line clearing contractors to its construction specification. Every line mile trimmed in 2028 may comply with DTE's specification, but that does not mean DTE trimmed one-fifth of circuit miles. The additional cost of ensuring compliance is necessarily less than the cost to customers resulting from poor reliability and the cost to ratepayers to get back on cycle DTE falls behind again. The Commission should adopt Mr.

[690] Alvarez Direct, 6 TR 3957-8.

[691] Steudle Rebuttal, 6 TR 3020-2.

[692] Steudle Rebuttal, 6 TR 3021 (referencing Steudle Direct, 6 TR 2993-94).

Alvarez' recommendation for a comprehensive, independent audit starting right after the last year of the Surge (2025 or 2026), which should serve as the baseline to measure future audits.

As it faces the end of the Surge, the Company proposes to explore risk-based variable cycle trimming as it approaches the end of the ETTP surge with the investment of $3.824 million in 2024 and a total investment of $6.9 million for a risk prioritization model.[693] According to Ms. Steudle, the model leverages LiDAR, advanced analytics, and machine learning to estimate the probability of vegetation-driven failures and develop optimal trim cycles.

On behalf of CUB, MEC, and NRDC, witness Denzler testified regarding the risk model.[694] He noted the importance of assessing risk at the sub-circuit level and considering the number of customers and outage duration. He also noted the importance of assessing mitigation costs – especially labor and equipment – to optimize tree trim spending. Mr. Denzler recommended that the Company evaluate the relevant costs and benefits over time to effectively evaluate the model, using actual benefits where available, reasonable projections of benefits, and internal and external benchmarking. He recommended monitoring model performance over time to ensure trim resources deploy optimally. To that end, he recommended an annual audit and evaluation of trim planning and the risk prioritization model.

Company witness Steudle opposed Mr. Denzler's recommendation, noting the model is already built and the Company "believes it will provide positive benefits to customers," so it is not prudent to invest in additional tools.[695] Instead, the Company is using the testing the model to defer trimming on some cycles, which it will assess for reliability and future trim costs.

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[693] Steudle Direct, 6 TR 2987-91; Ex A-12 Sch B5.4 p. 17 line 24.

[694] Denzler Direct, 6 TR 3774-6.

[695] Steudle Rebuttal, 6 TR 3022-3.

The Commission should adopt Mr. Denzler's recommendation notwithstanding the Company's resistance to evaluation and potential refinement of its model. The Commission should be concerned about the Company's unwillingness to invest time to evaluate whether its nearly $7 million investment in the model is performing well or could be improved.

Moreover, the Commission should be concerned with the Company's proposed use of the model to support delaying tree trimming cycles on some circuits, without addressing the opportunity to increase trimming cycles when line conditions support more aggressive vegetation management.[696] The Company so far proposed to delay trimming on 2,000 miles of on-cycle circuits but has not identified any miles to evaluate shorter cycles. The Company should consider avoided customer and reactive cost benefits associated with more aggressive trimming as part of its modeling; it is not clear the model considers avoided customer outages in the benefits analysis. Doing so may support the cost-effectiveness of shorter cycles. DTE asserts the model will reduce trim costs 5% annually relative to the 5-year cycle,[697] which suggests the Company is anticipating, on average, longer trim cycles (less trimming), not shorter cycles (more trimming). This dovetails with Mr. Alvarez' concerns about the Company falling behind the 5-year trim cycle.

The Commission should audit the tree trim prioritization model to guard against the potential that it becomes another self-serving model to justify the Company's preferred approach to distribution system maintenance – *i.e.*, decreasing O&M that is demonstrably cost-effective while increasing capital spending without demonstrating cost-effectiveness.

[696] Steudle Direct, 6 TR 2990.

[697] *Id* at 6 TR 2991.

E. Outage Credit Recovery: The Commission should reject DTE's proposal for recovery of outage credits for a wide variety of causes and should limit recoverability to outages caused by the transmission operator or another utility, and on the condition that DTE seek recovery of costs from the responsible party.[698]

Two electric rate cases ago, in U-20836, DTE requested Commission approval to use deferred accounting for outage credits and seek recovery in future cases.[699] Several parties opposed the Company's proposal, and Staff recommended that DTE's recovery of outage credits be limited to "outages that are not within the company's control to resolve such as outages caused by the transmission operator and outages caused by customer negligence."[700] The ALJ recommended that the Commission direct DTE to work with Staff toward the full development of Staff's proposal, and the Commission adopted that recommendation:

> [T]he Commission adopts the ALJ's findings and conclusions and directs DTE Electric to work with the Staff toward the full development of the Staff's proposed limited recovery of outage credits … [I]t is reasonable that the company have the ability to recover outage credits when the outage was caused by customer negligence or the transmission system operator, among other limited circumstances as developed in collaboration with the Staff.[701]

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[698] MNSC believes that the following portions of the record are relevant to these issues:

- Revised Direct Testimony of DTE witness Neal Foley, 2 TR 96-9; Foley Rebuttal, 2 TR 145-51.
- Direct Testimony of Staff witness Nicholas Evans, 6 TR 5229-32.
- Revised Direct Testimony of MNSC witness Douglas Jester, 6 TR 3790-4.
- Direct Testimony of GLREA witness John Richter, 6 TR 4858-62.
- Direct Testimony of DAAO witness Jackson Koeppel, 6 TR 4395-7; Direct Testimony of DAAO witness Toyia Watts, 6 TR 4670-76.
- Direct Testimony of Ann Arbor witness Melissa Stults, 6 TR 4256-9.

[699] Case No. U-20836, November 18, 2022, Order, pp. 363-4.

[700] *Id*. at 366.

[701] *Id*. at 366-67, citing PFD, p. 603.

In this case, DTE makes its own proposal for recovering outage credits. DTE witness Neal Foley testified that the Company discussed its proposal with Staff;[702] but is obvious that DTE did not develop the proposal collaboratively with Staff as the U-20836 Order directed.

DTE proposes to recover the cost of credits paid for outages that exceed the duration limit in Rule 46 if the outages are caused by a transmission operator or other utility, public interference, or animal interference.[703] DTE proposes to recover the cost of credits paid for outages that exceed the frequency limit in Rule 46 if the outages are caused by a transmission operator or other utility, public interference, animal interference, ice, lightning, wind, or other weather.[704] It is fair to ask whether there are any outage causes for which DTE does not seek to recover the cost of credits paid for exceeding the outage frequency limit.

Several parties to this case opposed DTE's overreaching proposal. MNSC witness Douglas Jester testified that it "is reflective of DTE Electric's continuing resistance to accountability for its performance as owner and operator of its distribution system."[705] Other than outages attributable to a transmission operator or other utility – which DTE should be able to recover only if it also pursues cost recovery from the responsible party – Jester opined that the Commission should reject DTE's proposal.[706]

With respect to duration, Jester noted that "[a]n 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."[707] He also

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[702] Foley Direct, 2 TR 97.

[703] *Id* at 2 TR 98; for Rule 46, see Mich Admin Code, R 460.746.

[704] *Id* at, 2 TR 98.

[705] Jester Direct, 6 TR 3793.

[706] *Id*.

[707] *Id*.

noted that "[i]f 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."[708] As to animal interference, that 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."[709]

With respect to outage frequency, Jester noted that "[t]he Commission's outage frequency limits, at 6 or more in a 12-month period, are already generous to the utility."[710] Further, "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."[711] Jester said that DTE's rationale that it controls restoration time but not the frequency of weather events "is unavailing because the Company does control the vulnerability of its distribution system to weather."[712]

Finally, witness Jester noted that "DTE Electric has persistently had amongst the worst reliability records of any investor-owned utility over several decades."[713] He presented data from CUB's 2023 utility performance report showing that DTE's reliability is worse than the U.S. average by almost every metric, while the Company's rates are much higher than average.[714] He noted that "[t]te Commission has given considerable attention to this problem over those decades to little avail."[715] He noted that the Service Quality and Reliability Standards "are one of the few

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[708] *Id*.

[709] *Id*.

[710] *Id*.

[711] *Id*. at 3793-94.

[712] *Id*. at 3794.

[713] *Id*.

[714] *Id*. at 3791.

[715] *Id*. at 3794.

measures that the Commission has undertaken to hold utilities accountable for performance;" and that "[f]or the Commission to grant this request by DTE Electric would demonstrate the Commission's abject inability to hold a utility accountable for its performance."[716]

Staff witness Nicholas Evans also testified that the Commission should reject DTE's proposal. Mr. Evans agreed with deferring the costs related to credits eligible for recovery, but recommended that "recovery should be far more limited than what DTE Electric has proposed."[717] Evans recommended that "for outages that exceed the duration limit, only those outages caused by a transmission operator or another utility should be recovered from ratepayers."[718] For the frequency limit, Mr. Evans recommended that only outages caused by the transmission operator, another utility, or public interference should be recoverable.[719]

GLREA witness John Richter made similar recommendations to witnesses Jester and Evans.[720]

In rebuttal, DTE witness Foley conceded that Staff's recommendation "is reasonable."[721] Mr. Foley expressed some uncertainty as to whether MNSC witness Jester or GLREA witness Richter supported the inclusion of public interference as a recoverable outage code for frequency-related outages, as Staff witness Evans did.[722] MNSC does not support recovery of outage credits for frequency exceedance due to public interference. The Commission should reject DTE's proposal and limit recoverable outage credits to those caused by the transmission operator or

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[716] *Id.*

[717] Evans Direct, 6 TR 5230.

[718] *Id.*

[719] *Id.*

[720] Richter Direct, 6 TR 4858-62.

[721] Foley Rebuttal, 2 TR 148.

[722] *Id.*

another utility, and then only on condition that DTE seeks recovery of costs from the responsible party.

In addition to the testimony just discussed, DAAO witnesses Koeppel and Watt and Ann Arbor witness Stults recommended that the Commission reject any recovery of outage credits.[723] DAAO witnesses Koeppel and Watt also recommend that the Commission establish an hourly outage credit.[724] MNSC takes no position on these proposals.

[723] Koeppel Direct, 6 TR 4397; Watts Direct, 6 TR 4674; and Stults Direct, 6 TR 4259.

[724] Koeppel Direct, 6 TR 4397; and Watts Direct, 6 TR 4673-74.

F. Energy Supply O&M (Reserved)

G. Fuel Supply and MERC Fuel Handling (Reserved)

H. Other Power Generation O&M (Reserved)

I. Nuclear O&M (Reserved)

J. IT O&M (Reserved)

K. Marketing O&M (Reserved)

L. Merchant Fees (Reserved)

M. Uncollectible Expense (Reserved)

N. Supplemental Savings (Reserved)

O. Pension/OPEB/Benefits (Reserved)

P. Healthcare Expense (Reserved)

Q. Incentive Compensation (Reserved)

R. Administrative & General O&M (Reserved)

S. Miscellaneous O&M (Reserved)

T. Corporate Memberships (Reserved)

U. VSIP: The Commission should reduce projected O&M expense to account for cost reductions resulting from DTE's large-scale voluntary buy-out program.[725]

At the beginning of DTE offered a Voluntary Separation Incentive Package (VSIP) – i.e., a buyout – to 1,025 of its employees and 1,622 DTE Energy Corporate Services LLC employees.[726]

[725] MNSC believes that the following portions of the record are relevant to these issues:

- Exhibit A-13 Schedule C5;
- Revised Direct Testimony of CUB-MN witness Joshua Denzler, 6 TR 3777-80; Confidential Direct Testimony of Mr. Denzler, 6 TR 5259-62;
- Ex CUB-14 and -14C;
- Direct Testimony of AG witness Sebastian Coppola, 6 TR 3687-8;
- Ex AG-45;
- Rebuttal Testimony of DTE witness Matthew Fix, 6 TR 2911-2914.

[726] Denzler Direct, 6 TR 3777; see also, Ex AG-45.

Of those, 140 DTE Electric employees and 249 Corporate Services accepted.[727] The cost of the buyouts is $30.6 million in 2024 and DTE estimates that savings from the staffing reductions will be up to $20.2 million in 2025.[728]

DTE takes the position that future savings from the buyouts should not be included in this case but instead should be included in future rate cases.[729] DTE is planning to hire backfills for some of the departed employees; the number of those employees and the estimated annualized O&M cost are included in a confidential exhibit.[730] DTE estimates total projected O&M savings of $20.2 million in 2025 after adding in the offsetting expense for the backfill hires.[731]

CUB-MN witness Joshua Denzler testified that "it does not make sense that the Company would include costs for employees that are no longer there."[732] Rather, DTE "should have to justify the expense of additional headcount above the VSIP-departures, not automatically receive those funds and then justify it down later."[733] The Company has not done so. Instead, DTE simply states that its "estimate will continue to evolve..."[734] Therefore, Mr. Denzler 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."[735] That new baseline should be a reduction of O&M expense by $20.2 million.

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[727] *Id*.

[728] *Id*.

[729] Ex AG-45, p. 3.

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

[731]Ex CUB-14, Response to MNSCDE-13.2b; see also Ex AG-45, p. 3.

[732] Denzler Direct, 6 TR 3779.

[733] *Id*.

[734] *Id*.; Ex CUB-14.

[735] Denzler Direct, 6 TR 3780.

Attorney General witness Sebastian Coppola outlined the same facts and reached a similar conclusion.[736] He stated that the projected 2025 O&M expense savings of $20.2 million "are real and significant and should be included in the projected test year as a reduction of future O&M expenses."[737] To be conservative, however, Mr. Coppola "included only half, or $10.1 million, of the currently estimated cost savings of $20.3 million as a reduction to the O&M expense for the projected test year."[738] He reasoned that "[t]he remaining half of the cost savings plus the cost savings that the Company will retain during 2024 will go a long way to offset the costs that the Company will incur in 2024 to achieve those savings."[739]

In rebuttal, DTE witness Matthew Fix argued against *any* reduction in projected 2025 O&M expense due to these large-scale buyouts.[740] He asserted that "[i]t is premature to include any savings from the VSIP in the Company's revenue requirement" because the "purpose of the VSIP was to realign the workforce to support the changing nature of the Company's work" and not to reduce costs.[741] He asserted that DTE "continues to assess the need to fill key positions which will impact any actual savings that may potentially be realized in 2025."[742] Mr. Fix said the assumed savings were only an assumption and "will continue to evolve as decisions regarding the actual number of positions filled are made throughout the remainder of 2024."[743] He recommended that "it is more prudent to wait until any savings are actually realized which can then be reflected

[736] Coppola Direct, 6 TR 3687-8.

[737] *Id*.

[738] *Id*.

[739] *Id*.

[740] Fix Rebuttal, 6 TR 2911-2.

[741] *Id*. at 2911.

[742] *Id*. at 2912.

[743] *Id*.

in the Company's future revenue requirements."[744] He also argued that "[b]ecause the Company has not sought to recover the $30.6 million in costs related to the separation payments accrued in 2024, it would be unreasonable to include a reduction to the Company's total O&M expense of the estimated savings without any recognition of the costs incurred by the Company."[745]

In evaluating Mr. Fix's rebuttal, first it is important to do some level-setting. DTE offered the buyouts at the very beginning of 2024. Mr. Fix filed his rebuttal at the end of August 2024. The question before the Commission is, what is a reasonable projected O&M expense for employees in 2025? When Mr. Fix filed his rebuttal, DTE had been working on the buyouts and the backfill hires for eight months. There were only four months left in 2024. The range of possible employee expenses in 2025 resulting from the buyouts and backfill hires is not nearly so wide as Mr. Fix wants to characterize it.

More fundamentally, this is DTE's case. DTE is seeking to re-set rates based on expenses projected for 2025. "In a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections."[746] Further, "the burden is on the company to prove the accuracy of each and every test year projection."[747] The burden is on DTE to demonstrate the accuracy of its test year projections – not on the intervenors to demonstrate that the projections are inaccurate.[748]

With respect to the VSIP, the staffing reductions are known. The full extent of future hires, and how much those hires will offset savings from the departures, is not known. That is the

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[744] *Id*.

[745] *Id*.

[746] Case No. U-15768, Jan. 11, 2010, Order, pp. 9-10; see also, Case No. U-17895, Sept. 8, 2016, Order, p. 4.

[747] Case No. U-20963, Dec. 22, 2021, Order, p. 10.

[748] *S C Gary, Inc v Ford Motor Co,* 92 Mich App 789, 803-804; 286 NW 2d 34 (1979) (when one party has the burden of proving a fact, the other party does not have the burden of proving the opposite fact).

foreseeable consequence of conducting buyouts in 2024 and filing a rate case with a fully projected test year of 2025. One thing is certain: Approving O&M expense for 2025 based on pre-buyout staffing levels will result in the Company over-earning in 2025. The only question is by how much.

Mr. Fix asks the Commission to sign off on over-earning because DTE cannot or will not say how much the over-earning will be reduced by new hires. That position is wholly untenable. The Commission should adopt Mr. Denzler's straightforward adjustment based on known staffing reductions, and DTE can seek approval of expense increases due to the new hires in its next rate case. Alternatively, and at a minimum, the Commission should adopt Mr. Coppola's proposal – which gives the Company credit for a large offsetting expense for new hires but at least is better than Mr. Fix's position.

As to the cost of the buyouts, DTE is free to return to the Commission in its next rate case with a request to amortize and recover that cost over a reasonable period of time as an offset to the going-forward savings generated by the lower staffing levels.

V. REVENUE DEFICIENCY (RESERVED)

VI. OTHER REVENUE RELATED ITEMS

A. Incentive Compensation Tracker Mechanism (Reserved)

1. Low Income Programs: The Commission Should Modify DTE's Low-Income Customer Programs.[749]

An astonishing number of DTE's residential customers live in poverty, and many more live close to the line. These customers struggle to afford their utility bills and other necessities,

[749] MNSC believes the following is the record on this issue:

- Direct Testimony of DTE witness Jason E. Sparks, 6 TR 2354-73; Rebuttal Testimony of Mr. Sparks, 6 TR 2378-98; Ex A-41, Schedule FF1 and FF2;

and the number of struggling customers grows with every electric rate increase. Recognizing this problem, DTE has established several programs intended to help eligible low-income customers pay their bills and maintain consistent electric service. These programs include the Low-Income Self Sufficiency Program (LSP), which provides bill payment assistance and targeted energy efficiency measures funded by the Michigan Energy Assistance Program (MEAP); the $40 monthly Low-Income Assistance (LIA) credit, which is often but not always provided in conjunction with the LSP; and the $8.50 monthly Residential Income Assistance (RIA), designed to offset the fixed monthly customer charge. DTE also recently completed a two-year pilot, the Payment Stability Plan (PSP), which was DTE's version of a Percentage of Income Payment Plan (PIPP).

Each of these programs provides some level of assistance, but that level of assistance is often too low to be meaningful or inaccessible to those who need it. Even with these programs, thousands of DTE customers carry excessive energy burdens, accumulate large arrearages, and experience threatened or actual shut-off for nonpayment. Unaffordability also imposes costs on DTE's other customers. For example, DTE projects $50.9 million in uncollectible expense for the test year.[750] Increasing average residential electric bills by $132 per year, as DTE proposes to do in this case,[751] will only make matters worse. More help, and more effective help, is needed.

Toward that end, DTE proposes increasing its LIA credit from $40 to $50 so that the program provides roughly the same percentage reduction in bills as when it was first implemented.

- Direct Testimony of NRDC, MEC & CUB witness Roger Colton, 6 TR 3856-3912; Ex NRD-1;
- Direct Testimony of Staff witness Elaine Braunschweig, 6 TR 3520-8; Rebuttal Testimony of Ms. Braunschweig, 6 TR 3539-49; and Ex S-17.2; and Cross Examination of Ms. Braunschweig. 6 TR 3550-81;
- Exs MEC-127, MEC-128, and MEC-129;
- Direct Testimony of DAAO witness Justin Schott, 6 TR 4500-16; Direct Testimony of DAAO witness Toyia Watts, 6 TR 4686-9.

[750] Sparks Direct, 6 TR 2357.

[751] Application, Attachment 4, p. 1, typical residential bill increase of $11.03 per month multiplied by 12 months.

DTE's proposal is a step in the right direction but does not go far enough. To ensure meaningful and sufficient assistance, MNSC urge the Commission to adopt the recommendations of their expert witness Roger Colton, who has four decades of experience working on low-income utility issues.[752] In his testimony, Mr. Colton presents a detailed and thorough data analysis on affordability for DTE's low-income customers and makes the following recommendations:

1. DTE should maintain its $8.50 RIA credit but direct it to customers with incomes above 150% of the federal poverty level (FPL) and shift current RIA participants with incomes at or below 150% FPL to the LIA program.
2. DTE should transition from offering a flat LIA credit to eligible households at all income levels to a tiered program that increases the LIA credit amount for households with lower incomes so that bill burdens are meaningfully reduced.
3. DTE should make it easier for customers to demonstrate program eligibility. For example, to the extent that participation in a public assistance program would demonstrate an income eligibility for the RIA, DTE should accept proof of participation in that assistance program as proof of RIA eligibility. DTE should also enroll customers in LIA based on self-attestation of SNAP participation.
4. DTE should allow LSP participants the opportunity to obtain complete forgiveness of total pre-program arrears, provide arrearage forgiveness credits on a pro rata basis for each complete bill payment made over 24 months, and provide retroactive credits when a previously missed payment is made.
5. DTE should tier its LSP arrearage forgiveness benefits by allowing households with incomes at or below 50% FPL to earn forgiveness in 12 months instead of 24.

[752] Ex NRD-1.

No party disagreed with Mr. Colton's analysis of the nature and scope of the affordability problem, or with the premise that DTE's low-income programs can be improved. Staff and DTE, however, mostly want to maintain the status quo until the statewide Energy Affordability and Accessibility Collaborative (EAAC) and its Affordability, Alignment, and Assistance (AAA) subcommittee make recommendations.

There is no good reason to wait. Mr. Colton's recommendations are reasonable, evidence-based, and grounded in deep knowledge and experience. The Commission should adopt them.

2. Lower-income households are hit harder by inflation and carry heavier energy burdens than higher-income households.

Recognizing that the US is experiencing a period of high inflation, Mr. Colton examined the impact of inflation on low-income households. He explained that inflation hits low-income households harder for three primary reasons: 1) they spend a higher percentage of their income on necessities, which are prone to higher and faster inflation; 2) they are already consuming the cheapest goods and cannot switch to lower-cost alternatives like higher-income households; and 3) they have smaller cash reserves to help them get by.[753]

Next, Mr. Colton reviewed the widening gap between the rising FPL and DTE's increasing electricity prices, noting that DTE's prices have risen sharply compared to incomes since 2020.[754] The gap forces households to choose between paying their energy bills and other necessary expenses, making it "less likely that DTE bills can and will be paid on a sustainable basis."[755] As

[753] Colton Direct, 6 TR 3864-8.

[754] *Id* at 3868-9.

[755] *Id* at 3869.

income drops, energy insecurity rises. In Michigan, nearly a quarter of households with incomes at or below $35,000 report finding it "very difficult" to pay their household expenses.[756]

Next, Mr. Colton analyzed the energy burdens that DTE's proposed rate increase will impose on residential customers by both household income and FPL. To be affordable, a household's total home energy expense from all fuel types should not exceed 6%.[757] Where a household uses both electricity and natural gas, it is reasonable to allocate more expense to electricity.[758] Accordingly, Mr. Colton used a 4% energy burden as the threshold for affordability – burdens at or below 4% are affordable and burdens above 4% are excessive.

Among households with incomes up to $39,999, the range of energy burdens at DTE's current rates varies dramatically from the impossibly unaffordable 28.3% for households below $10,000 to the just-barely affordable 3.8% for those between $35,000 and $39,999.[759] With DTE's proposed rate increase, even those households at the top of the range will face marginally unaffordable energy burdens of 4.1%.[760] The range of energy burdens is also striking by FPL, which considers both household income and household size (e.g., 100% FPL for a single individual is $15,060 and $25,820 for a family of three).[761] For households from 0-50% FPL at the low end of the income spectrum to 150-200% FPL at the high end, burdens range from 15.5% to 3.5% at DTE's current rates and 17% to 3.9% at proposed rates.[762]

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[756] *Id* at 3871.

[757] *Id* at 3872, n. 10.

[758] *Id* at 3872, n. 10.

[759] *Id* at 3873.

[760] *Id* at 3873.

[761] *Id* at 3875.

[762] *Id* at 3876.

3. DTE's Current Low-Income Assistance Programs

DTE witness Jason Sparks outlined DTE's current low-income assistance programs, which DTE intends to advance several goals, including:

- Ensuring continued access to and preventing interruptions in energy service;
- Reducing arrearages;
- Promoting regular bill payments;
- Reducing consumption; and
- Meeting immediate needs while supporting long-term stability.[763]

DTE's low-income assistance programs include:

- Low Income Self-Sufficiency Program (LSP). The LSP is DTE's Affordable Payment Program (APP) and funded by MEAP dollars. [764] It is a two-year program that allows households with incomes at or below 150% FPL "to make affordable monthly payments based on income and energy usage."[765] It includes wraparound services, arrearage forgiveness, and other supports. [766] In 2023, it was updated to recognize more granular income tiers, remove its previous energy consumption cap, restructure its arrearage forgiveness payments and remove its previous arrearage cap, restructure its bill credits, and allow the plan amount to change based on periodic reevaluations.[767] For 2022-2023, 23,750 households were enrolled in the LSP.[768]

[763] Sparks Direct, 6 TR 2358-9.

[764] *Id* at 2362-3.

[765] *Id* at 2362.

[766] *Id* at 2362.

[767] *Id* at 2363.

[768] *Id* at 2365.

- Residential Income Assistance (RIA). RIA provides a flat $8.50 monthly credit to households with incomes at or below 150% FPL "as verified by an authorized State or Federal agency."[769] Households receiving a Home Heating Credit (HHC), State Emergency Relief (SER), or one-time assistance are automatically enrolled; other households may be manually enrolled.[770] Households receiving the RIA cannot receive the LIA and vice versa.[771] In 2023, a monthly average of 75,522 customers received the RIA; DTE projects that number to grow to 83,000 for the test year.[772]
- Low-Income Assistance (LIA). LIA provides a flat $40 monthly credit to households with incomes at or below 150% FPL.[773] Participation in the LIA program is capped at an annual average of 32,000 customers, and participation hit the cap in 2022 and 2023.[774] DTE prioritizes LSP participants and RIA recipients for receipt of the LIA credit.[775] The LIA was established as a pilot rate in Rate Schedule D1.6; the Company now proposes to eliminate Rate Schedule D1.6 and make the LIA available to all base residential rate schedules.[776] The Company also proposes to increase the LIA from $40 to $50 "to align the financial support provided to low-income customers receiving LIA with the originally approved credit offset as a percentage of their bills."[777]

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769 *Id* at 2369.

770 *Id* at 2369.

771 *Id* at 2369.

772 *Id* at 2370.

773 *Id* at 2371.

774 Ex A-16 Sch F8 – Rate Schedule D1.6.

775 Sparks Direct, 6 TR 2371.

776 Ex A-16 Sch F8 – Rate Schedule D1.6; Sparks Direct, 6 TR 2373.

777 Sparks Direct, 6 TR 2373.

- Payment Stability Plan (PSP) Pilot. The PSP is a two-year PIPP pilot for households with income at or below 200% FPL.[778] For participants who receive both electricity and gas from DTE, payments are capped at 10% of household gross income; electricity-only payments are capped at 6%.[779]

4. The current flat RIA and LIA credits do little to alleviate energy burdens for households with the lowest incomes.

Mr. Colton analyzed the impact of the flat RIA and LIA credits on household energy burdens under DTE's proposed new rates and found they do little to alleviate those burdens for households with the lowest incomes. Receipt of the $8.50 RIA does not make bill burdens affordable even for households at the top of the program's income eligibility range (125-150% FPL). These households would see their average energy burden drop from 4.9% to 4.6% upon application of the RIA credit but still carry a burden greater than the 4% affordability threshold.[780] For households at the lower end of the eligibility range, their energy burdens remain impossibly high at 15.9% even after application of the RIA credit.[781]

Receipt of the larger LIA credit makes energy genuinely more affordable for households with incomes toward the top of the eligibility range, but still leaves households with lower incomes behind. Even at the current $40 level, it makes bill burdens affordable or very nearly so for households with incomes above 100% FPL.[782] At DTE's proposed $50 level, bill burdens would be as low as 3% for households with incomes between 125 and 150% FPL.[783] However, burdens

[778] *Id* at 2367.

[779] Sparks Direct, 6 TR 2367.

[780] Colton Direct, 6 TR 3882.

[781] *Id* at 3882.

[782] *Id* at 3889.

[783] *Id* at 2889.

for households with incomes between 0 and 50% FPL would remain more than two-and-a-half times the affordability threshold at 10.4%.[784]

5. Redirecting the RIA credit to higher-income households and establishing tiered LIA credits would enable both programs to have a meaningful impact on affordability.

Based on his analysis of the impact of the RIA and LIA credits on bill burdens, Mr. Colton recommends redirecting the relatively small RIA credit to households with higher incomes and establishing a tiered system of LIA credits ranging between $45 and $95 depending on income level. These recommendations would enable both programs to have a meaningful impact on affordability and better meet customers' immediate needs in times of financial difficulty while promoting long-term sustainable and uninterrupted energy access, reduced arrearages, and regular bill payments. These recommendations would also have positive impacts for other DTE customers by generating savings from reduced Company operating costs that will be reflected in rates.[785] Additionally, Mr. Colton recommends measures to make it easier for customers to demonstrate eligibility for the RIA and LIA, removing the LIA participation cap, restructuring arrearage payment benefits, and allowing DTE to reconcile its LIA program costs each year.

Both Company witness Sparks and Staff witness Braunschweig argue that any proposed modification of DTE's low-income programs – except for DTE's proposed LIA credit increase, which only Staff opposes – should be left for the EAAC and its AAA subcommittee to consider.[786] This brief will address that argument separately after discussing the details of Mr. Colton's

[784] *Id* at 3889.

[785] *Id* at 3879.

[786] Sparks Rebuttal, 6 TR 2391; Braunschweig Rebuttal, 6 TR 3545-6.

recommendations and any rebuttal to those recommendations unrelated to the role of the EAAC and AAA.

6. Redirecting RIA credits

There are two main reasons to shift the RIA credits to higher-income households. First, as discussed above, they are too small to meaningfully improve affordability for households with incomes at or below 150% FPL. Second, households between 150 and 250% FPL or 60% of State Median Income (SMI) still have fragile incomes and are likely to experience substantial difficulties paying their utility bills and other necessary expenses.[787]

In rebuttal, DTE witness Sparks acknowledged the need for assistance for households with incomes greater than 150% FPL but concluded that Michigan's definition of an "eligible low-income customer" precluded it from adopting Mr. Colton's recommendation.[788] Similarly, Staff witness Elaina Braunschweig suggested Mr. Colton's recommendation would conflict with MCL 460.11(2), which authorizes the Commission to establish low-income rates, and MCL 460.10t, which defines an eligible low-income customer as one "whose household income does not exceed 150% of the poverty level . . . or who receives . . . [a]ssistance from a state emergency relief program," food stamps (i.e., SNAP benefits), or Medicaid.[789]

While MCL 460.11 and 460.10t may preclude full implementation Mr. Colton's recommendation at this time, Mr. Colton's analysis and reasons for extending support to higher income families are sound. MNSC urge the Commission to consider ways to address the needs of households with incomes between 150 and 250% FPL or 60% SMI, including supporting

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[787] Colton Direct, 6 TR 3884-5.

[788] Sparks Rebuttal, 6 TR 2391.

[789] Braunschweig Rebuttal, 6 TR 3547; MCL 460.11(2); MCL 460.10t(6)(b).

legislative changes that would expand the definition of eligible low-income customers or authorize the Commission to establish special rates for this population.

7. Tiered LIA Credits

Providing different LIA credit amounts based on income will provide real energy burden relief and better promote many of DTE's stated program goals. Mr. Colton recommends the following three tiers:

- For incomes at 0-50% FPL, a bill credit of $95 per month
- For incomes at 50-100% FPL, a bill credit of $80 per month
- For incomes at 100-150% FPL, a bill credit of $45 per month

By implementing these tiers, DTE would reduce energy burdens to affordable or very-nearly affordable levels across the whole range of income-eligible households. Households in the 0-50% FPL tier would have energy burdens of 4.5% compared to more than twice that (10.4%) with DTE's proposed flat $50 credit.[790] Households with incomes above 100% FPL would see slightly smaller energy burden reductions with a $45 credit than with DTE's proposed $50 credit but still have bill burdens below the 4% affordability threshold.[791]

Reducing bill burdens is an effective way to improve payment patterns and reduce arrearages. Reviewing the State of New Hampshire's tiered Electricity Assistance Program (EAP), Mr. Colton examined arrearages for customers with bill burdens ranging from 4% or less through 20% or more. Customers with burdens of 4% or less made up 40% of EAP participants but just 9-13% of unpaid program balances, with relatively low arrearage amounts.[792] Mr. Colton concluded,

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[790] Colton Direct, 6 TR 3893.

[791] *Id* at 3893.

[792] *Id* at 3891-2.

"As the tiered burdens reduced bills to an affordable percentage of income, . . . the payment patterns of program participants correspondingly improved as well."[793]

1. <u>Other changes would further improve DTE's low-income programs.</u>

i. Streamlining how customers establish eligibility for RIA and LIA

Mr. Colton recommends DTE streamline how customers establish eligibility for RIA and LIA. Where receipt of public assistance would qualify a customer for participation in the RIA, DTE should accept documentation of participation in that public assistance program as documentation of RIA eligibility.[794] Where a customer can provide documentation of their participation in the SNAP program, no further documentation should be required for them to establish LIA eligibility.[795] Staff did not disagree, but indicated a belief that DTE already offers self-attestation to RIA customers and proposed the following language be added to the RIA and LIA tariffs to explicitly allow for it: "If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return."[796]

ii. Cost recovery for the LIA

Mr. Colton recommends that the Commission allow DTE to reconcile its actual LIA costs to its projected LIA costs annually and track any excess or deficit as a regulatory asset to be recovered in its next rate case.[797] Mr. Colton explains that cost recovery should include only net incremental costs, taking into account the positive impact the LIA program has on arrearages

[793] *Id* at 3892.

[794] *Id* at 3883.

[795] *Id* at 3903-4.

[796] Braunschweig Rebuttal, 6 TR 3548.

[797] Colton Direct, 6 TR 3894-5.

balances, working capital, collection expenses, and uncollectibles.[798] In rebuttal, Mr. Sparks asserts that DTE's projected LIA costs are grounded in historical actual costs that reflect the program's benefits and no additional analysis is needed.[799] MNSC acknowledges DTE addresses LIA costs through historical actual costs and, while maintaining there is room for improvement, reserves this issue for a future case.

iii. Removing the LIA participation cap

In light of the LIA program's positive impact on arrearages balances, working capital, collection expenses, and uncollectibles, Mr. Colton finds no justification for maintaining the cap on participation.[800] Mr. Colton recommends removing the LIA participation cap and allowing all eligible customers to participate.[801]

iv. Restructuring LSP arrearage payments

Mr. Colton recommends modifying the arrearage forgiveness elements of the LSP to allow participants to earn forgiveness of a pro rata portion of their pre-program arrears for each month they make a complete payment, irrespective of whether that payment is timely; to allow program participants to obtain complete arrearage forgiveness through the program; and to allow participants with the lowest incomes to obtain that complete forgiveness in 12 months instead of 24. Currently, the program grants forgiveness credits totaling $3,000 at three program points – $600 at the beginning of participation, $600 at the 12-month mark, and $1,800 at the 24-month mark.[802] Monthly arrearage forgiveness credits, however, would enable participants "to see a

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798 *Id* at 3895-3900.

799 Sparks Rebuttal, 6 TR 2390.

800 Colton Direct, 6 TR 3900.

801 *Id* at 3900.

802 Colton Direct, 6 TR 3909; Sparks Direct, 6 TR 2363.

continuing reduction in their pre-program arrearage balance."[803] Additionally, tiering the timeline for completion to allow households with incomes at 0-50% FPL would help offset the excessive energy burden that customers at these income levels face carry even after receipt of a LIA credit.[804]

8. The Commission should not wait any longer to improve DTE's low-income programs.

Staff witness Braunschweig opposes DTE's proposed increase to the LIA credit in her direct testimony and both witness Braunschweig and Company witness Sparks oppose Mr. Colton's recommendations in their rebuttal testimony – mainly on the grounds that modifications to DTE's low-income programs should be considered by the EAAC and its AAA subcommittee and not by the Commission in this case.[805] The Commission should reject the argument that it should not consider proposals to improve DTE's low-income assistance in this case, and must instead wait for the subcommittee of a workgroup to complete a report that may at some point in the future inform utility proposals that may or may not align with the subcommittee's preferences. The Commission can and should act to improve DTE's low-income programs now, before rates rise again and even more customers find themselves struggling to pay their electricity bills.

Witness Braunschweig has co-led the EAAC's AAA subcommittee since its inception in July 2021.[806] On direct, she argues that the Commission charged the EAAC in a previous DTE rate case, Case No. U-20836, with reviewing LIA enrollment data and making recommendations about enrollment to the Commission; and more recently directed the EAAC in Case No. U-20757, its docket for reviewing Michigan's response to the COVID-19 pandemic, to review Michigan

[803] *Id* at 3909-10.

[804] *Id* at 3911.

[805] Mr. Sparks distinguishes DTE's proposed LIA credit increase from Mr. Colton's recommendations, noting that a dollar amount increase requires no structural changes to the LIA program. Sparks Rebuttal, 6 TR 2385-6.

[806] Braunschweig Direct, 6 TR 3521; Braunschweig Cross, 6 TR 3559.

utilities' PIPPs and other offerings in addition to DTE's RIA and LIA programs.[807] She acknowledges that "Michigan's most vulnerable customers would benefit from additional assistance" but claims she is "not persuaded" that DTE's proposed LIA credit increase is supported by the "comprehensive analysis and diverse, collaborative input the Commission is looking for to inform utility energy assistance changes."[808] She offers for the AAA subcommittee to consider the proposal witness Sparks presented and recommends the Commission "not approve any changes to the structure of the credits and instead leave this issue to the EAAC until it completes its relevant Commission directives."[809]

Witness Braunschweig's opposition to DTE's proposed LIA credit increase is unjustified. On cross examination, witness Braunschweig acknowledged that, if the Commission approves DTE's proposed rate increase in this case, LIA participants not also enrolled in the LSP could see their monthly bills go up slightly even if DTE *does* increase the LIA credit amount by $10.[810] She admitted that no further analysis is required to conclude that rate increases will cause people to fall farther behind.[811] She also acknowledged that, since Mr. Colton first proposed increasing the LIA credit amount in 2019 in Case No. U-20561, the LIA has stayed the same while DTE's rates have gone up three or four times.[812] Mr. Colton in this case, while advocating for a tiered credit structure, provided ample evidence that a $10 LIA credit increase would reduce bill burdens.[813] In DTE's Gas Company's most recent rate case, Case No. U-21291, the PFD considered a similar objection

[807] Braunschweig Direct, 6 TR 3525 (citing Case No. U-20836, Order dated November 18, 2022, p. 407, and Case No. U-20757, Order dated December 21, 2023).

[808] *Id* at 3525-6.

[809] *Id* at 3527-8.

[810] Braunschweig Cross, 6 TR 3554.

[811] *Id* at 3556.

[812] *Id* at 3557.

[813] See, e.g., Colton Direct, 6 TR 3889, Table 9.

from Staff to a Company proposal to raise its LIA credit from $30 to $40 and sensibly rejected it, finding that "the LIA has proven effective, the increase is in the best interests of customers who urgently require bill relief, and this increase does not involve a change to the structure of the eligibility requirements or recovery mechanisms."[814] While better alternatives may exist and the LIA could be improved, the Commission should not reject a Company proposal to provide an additional $10 to some of its most vulnerable customers for no reason other than to wait for a report that it likely will not review for another year.[815]

In rebuttal, witness Braunschweig extends her argument to oppose other parties' proposals for improving DTE's low-income programs, including most of those Mr. Colton presented[816], and maintains that the Commission should do nothing until the EAAC and its AAA subcommittee complete their work. She states, "[S]taff recommends the Commission allow energy assistance restructuring analysis and recommendations to come from the AAA and Staff reporting on LIA, RIA, and PIPP pilots and hold off on utility energy assistance programmatic changes until that point."[817] Citing the "complicated landscape of energy assistance," she argues that improvements should be made "through the chronological format of a utility report, Staff-response, a comment-period, and Commission order."[818]

Respectfully, these arguments are misguided. Improvements cannot be made through the workgroup process, which can only result in nonbinding Staff recommendations for improvements

[814] Case No. U-21291, September 4, 2024, PFD, p. 393.

[815] The last Staff report filed in Case No. U-20757 was filed on March 16, 2023, and not reviewed in a Commission order until December 21, 2023, following a lengthy comment period. As witness Braunschweig has indicated the next report to address low-income programs is not expected until sometime in the first or second quarter of 2025 (Braunschweig Cross, 6 TR 3568), it is reasonable to conclude it could be December 2025 or later before the Commission reviews and issues an Order pertaining to that report.

[816] Witness Braunschweig did not disagree with Mr. Colton's proposal regarding self-attestation for SNAP benefit recipients and proposed related tariff language herself. Braunschweig Rebuttal, 6 TR 3548.

[817] Braunschweig Rebuttal, 6 TR 3546.

[818] *Id* at 3546.

that utilities are not required to implement. The AAA subcommittee is an informal group that operates without governing documents and its membership consists of whomever comes to its meetings – typically, a mix of representatives from Staff, utilities, and MEAP grantees, as well as some DTE customers and advocacy organizations.[819] It does not make decisions or even recommendations. Rather, Staff writes reports summarizing what the group has discussed and noting areas of disagreement.[820] Any recommendations are written by Staff.[821] In discovery, Staff could identify no proposals, reforms, or changes discussed at AAA meetings that have subsequently become included in DTE Electric tariffs or rates.[822]

Witness Braunschweig testified that Staff's report on utility LIA and RIA programs and PIPP pilots can be expected sometime in the first or second quarter of 2025.[823] She did not know how the workgroup process would play out after that and could only say that Staff "would like for the utilities to make recommendations" based on the outcomes of their PIPP pilots.[824] She agreed that additional proceedings would "[l]ikely" be necessary for any proposals to be implemented and admitted that utility recommendations would not have to align with the AAA subcommittee's preferences.[825]

In addition to the problems discussed above, Staff's opposition to the consideration of improvements to low-income programs in rate cases appears inconsistent with the Commission's interest in better integrating equity and environmental justice issues into rate cases and lowering

[819] Braunschweig Cross, 6 TR 3559, 3562-3.

[820] *Id* at 3563-4.

[821] *Id* at 3564.

[822] Ex MEC-127, p. 6.

[823] Braunschweig Cross, 6 TR 3568.

[824] Braunschweig Cross, 6 TR 3568-70.

[825] *Id* at 3570-1.

barriers to and promoting greater participation and transparency in rate cases, as expressed in its invitation to comment on the ratemaking process in Case No. U-21637.[826] MNSC and others submitted comments expressing concern about how carving issues out of rate cases could undermine regulatory oversight and public engagement.[827] Carving out the evaluation and approval of improvements to programs designed to help people with low incomes is wholly at odds with the integration of equity and environmental justice issues into rate cases, in addition to being counterproductive and even harmful.

Changes to a utility's low-income programs must be proposed and evaluated in contested rate case proceedings where parties have the opportunity to test the sufficiency of the evidence regarding their reasonableness and prudence and where the Commission has authority to approve utility spending on them.[828] If and when the workgroup process witness Braunschweig endorses results in actionable recommendations, those recommendations will still need to be voluntarily incorporated into utility proposals and presented in rate case proceedings like this one for evaluation and approval. That process will take years, has no guarantee to happen as envisioned, and all the while customers will almost certainly see their rates continue to rise and their energy burdens become more unaffordable.

Five years have passed since Mr. Colton first recommended changes to the LIA in Case No. U-20561, four years have passed since the inception of the EAAC workgroup[829], three years have passed since the AAA subcommittee first convened, and still DTE's LIA program remains the same. Further delay is unjust, unreasonable, and unnecessary. Parties to this rate case, including

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[826] Case No. U-21637, May 23, 2024, Order, p.4.

[827] Case No. U-21637, Comments by NRDC, et al, filed September 27, 2024, p. 8.

[828] See MCL 460.6a(1) (requiring changes to rates and rate schedules that will result in an increase in cost of service to customers to be approved under MCL 460.6a).

[829] The EAAC was established in July 2020. Braunschweig Cross, 6 TR 3561.

DTE, have presented the Commission with proposals to improve the LIA and other low-income programs and evidence to support them. Staff's aspirations for the workgroup process are not a good reason to delay consideration of the proposals and evidence presently before the Commission.

9. Conclusion

DTE's low-income programs provide important benefits but also need improvement. Mr. Colton's recommendations are based on thorough analysis of currently available data and grounded in his extensive expertise designing and evaluating low-income assistance programs. No one disputes the need for improved support for ratepayers with low incomes. The expectation that a workgroup will produce recommendations that may inform future improvements is not a good reason to refuse to make improvements that are possible now. The Commission should adopt Mr. Colton's recommendations.

B. RIA and LIA Program Changes (addressed in preceding section)

C. Cash Payment Requirements (Reserved)

D. Tree Trim Regulatory Asset – Return Rate [830]

MNSC opposes the Company's request for a return on its Enhanced Tree Trimming Project and Surge Regulatory Asset. DTE witnesses Lepczyk and Vangilder support application of the Company's long-term debt rate to the Enhanced Tree Trimming Project and Surge (ETTP) until such time as DTE pursues securitization of the asset.[831] Mr. Lepczyk noted the Commission

[830] MNSC believes the following portions of the record are relevant to this issue:
- Direct Testimony of DTE witness Kirk M. Vangilder, 6 TR 2817;
- Direct Testimony of DTE witness Timothy J. Lepczyk, 6 TR 2559-60; Rebuttal Testimony of Mr. Lepczyk, 6 TR 2565-6; and
- Direct Testimony of AG, MEC & NRDC witness Paul Alvarez, 6 TR 3955-6.

[831] Lepczyk Direct, 6 TR 2559-60; Vangilder Direct, 6 TR 2817.

previously approved the tree trim surge regulatory asset at the short-term debt rate in U-21297 but seeks in this case for the Commission to revisit that approach and instead approve recovery at the long-term debt rate.[832] According to Mr. Lepczyk, "[i]n past cases (e.g., Case No. U-21015), the Commission directed DTE Electric to retire existing long term debt and equity with the proceeds from the sale of the securitization property" and argued it is "therefore consistent that the return associated with the surge regulatory asset be commensurate with the capital that will ultimately be retired with the proceeds of that securitization."[833]

CUB-MEC witness Alvarez opposed the Company's request, instead recommending that the Commission provide *no rate of return* on the ETTP regulatory asset.[834] Mr. Alvarez opined that the tree trimming surge was the result of DTE's deferral of scheduled tree trimming year after year.[835] He stated that "[b]y authorizing a rate of return on the Surge regulatory asset the Commission would be rewarding the Company for the poor and self-interested tree trimming deferral decisions the Company has made in the past."[836] Mr. Alvarez further opined that by providing a return for shareholders of the ETTP regulatory asset the Commission creates "an economic incentive to make the Surge regulatory asset as large as possible" by possibly delaying securitization events.[837] He stated that such a delay is not in the ratepayer's interest because it "results in much higher costs for customers on the regulatory asset relative to the cost of the securitized loans."[838]

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[832] Lepczyk Direct, 6 TR 2559-60.

[833] Lepczyk Rebuttal, 6 TR 2565-66.

[834] Alvarez Direct, 6 TR 3955-56.

[835] *Id.* at 3955.

[836] *Id.*

[837] *Id.*

[838] *Id.*

In rebuttal, DTE witness Lepczyk responded to Mr. Alvarez's recommendation that the Company be provided with no rate of return on the ETTP regulatory asset by stating that that DTE should receive its long-term debt and equity capital rate because "in past cases…the Commission has directed the Company to retire long-term debt and equity with the proceeds of securitization."[839] This is not accurate. In U-21297 the Commission, authorized the return on the tree trim surge regulatory asset at the authorized *short-term rate*.[840] For these reasons, CUB-MEC recommends that the Commission either again maintain the authorized short-term rate or follow Mr. Alvarez's recommendation and provide no rate of return to the Company of the ETTP regulatory asset.

Denying a return on this cost would not be unprecedented, as seen in the Commission's decision rejecting DTE's request for a return on the cost of the Fermi III operating license issue. In Detroit Edison's 2011 rate case, the Commission approved inclusion in working capital of some but not all of DTE's Fermi license expenditures because it was not yet known whether the license application would become "'used and useful' to Detroit Edison's ratepayers.[841] Then in DTE Electric's 2015 rate case, the Commission initially disallowed inclusion of $102 million in Fermi license expenditures – even though Staff had found the amounts reasonable – "until the plant could be considered used and useful."[842] On rehearing, the Commission granted DTE approval to amortize the $102 million without a return on that amount.[843] The Commission explained that it favored a return of, but not on, the license expenditures because "[t]he utility will be made whole for the cost of seeking the license, but ratepayers will not be expected to continue to provide a

[839] Lepczyk Rebuttal, 6 TR 2566.

[840] Case No. U-21297, Dec. 1, 2023, Order, pp. 280.

[841] Case No. U-16472, Oct. 20, 2011, Order, p. 72.

[842] Case No. 17767, Dec. 11, 2015, Order, p. 39.

[843] Case No. U-17767, Jan. 19, 2016, Order on Rehearing, p. 6.

return on an asset whose real value is undefined at this point."[844] The Commission made the same decision again in DTE's next rate, U-18014.[845] Granting DTE a return of, but not on, the regulatory asset associated with the ETTP surge would be consistent with the Fermi III cases. Mr. Alvarez's alternative recommendation to deny a return on the regulatory asset is appropriate to provide short term relief for ratepayers until the next securitization filing that includes the accumulated surge spending.

At bottom, the Company should not be rewarded for its negligence in causing the surge spending in the first place. The Commission has acknowledged that a return on a regulatory asset is inappropriate when it shoulders ratepayers with costs for an asset that dubious value. The surge is effectively a remedy for prior maintenance (O&M) underspending, so any return on that spending should be minimized to the full extent, consistent with Mr. Alvarez's recommendations.

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[844] *Id*.

[845] Case No. U-18014, Jan. 31, 2017, Order, p. 51.

VII. COST OF SERVICE

A. Purchased Power Capacity Costs Allocation (Reserved)

B. State Reliability Mechanism Capacity Charge/Capacity Revenue Requirement (Reserved)

VIII. RATE DESIGN & TARIFF ISSUES

A. Residential Rate Design

1. Residential Senior Citizen Credit (RSC) Forecast (Reserved)

2. Electric Heating Customers

MNSC incorporates by reference its briefing below supporting future analyses of, *inter alia*, electric hearing and other subclasses, under the **Future Rate Cases, Further Study, Other** section and the *Cost of Service and Rate Design* subsection.

3. D1.6 and D1.11 TOU Rates (Reserved)

B. Commercial Rate Design (Reserved)

C. Streetlighting (Reserved)

D. EV Rates (Reserved)

IX. PILOT PROGRAMS

A. Slocum Battery (Reserved)

B. NWA Adaptive Microgrid (Reserved)

C. DR BTM Battery Storage (Reserved)

D. Residential Generator (Reserved)

E. Demand Response – Cost Effectiveness (Reserved)

F. Strategic Undergrounding Pilots are Cost Ineffective and Should End.[846]

In U-20836, DTE proposed a pilot to underground, among other assets, these service lines, which MNSC and others opposed because the program was incomplete and proved prohibitively cost-ineffective.[847] In U-21297, DTE projected $2.4 million in the 11-month bridge period and $1.9 million in the test year for program, but the ALJ found DTE "not establish the reasonableness and prudence of this new pilot project, as it provided no BCA and failed to comply with the

[846] MNSC believes the record on this issue consistent of the following:

- Direct Testimony of DTE witness Satvir S. Deol, 5 TR 1191-1204; Rebuttal Testimony of Mr. Deol, 5 TR 1263-6;
- Ex A-23 Sch M11 and M13, Ex A-21 Sch R1;
- Direct Testimony of AG, MEC & NRDC witness Dennis Stephens, 6 TR 4925-6; and
- Ex MEC-11.

[847] Case No. U-20836, November 18, 2022, Order, pp. 111-12 (limiting investment in Strategic Service and Undergrounding program "until the Appoline pilot is complete and a full report is available, and until a more robust analysis of the benefit/cost of strategic undergrounding is available.").

Commission's instructions in the November 18 order regarding completion of, and reporting back on, the results of the Appoline pilot."[848] The Commission agreed with the PFD:[849]

> [T]he Commission finds that the Appoline pilot design lacked rigor if there is nothing left to learn after undergrounding only two-thirds of targeted customer service lines. The Commission also agrees with the Staff that the report lacks discussion of health, safety, reliability, vulnerability, and distribution issues. The Commission, in this instance, was looking for a pilot with an accompanying comprehensive BCA. Undergrounding is such an expensive proposition for ratepayers, that while the Commission believes there may be instances where undergrounding is the best option, it requires a BCA to demonstrate (before that expenditure is undertaken) that undergrounding is superior to other alternatives on a quantitative basis. The Fairmount pilot is also expensive and likewise offers no BCA. The Commission adopts the ALJ's recommendation to disallow this bridge period and test year expenditure in rate base.

In this case, DTE proposes to substantially increase spending on this pilot program:[850]

2022	2023	2024	2025
$0.462 million	$3.830 million	$16.644 million	$16.191 million

Company witness Deol supported the Company's investment plan for the Strategic Undergrounding Program.[851] He summarized the Company's experience with the Appoline project, which was cost ineffective, and presented the results of a BCA analysis confirming as much.[852] He also presented the Company's plans to underground 4 miles in the Buffalo-Charles neighborhood.[853] The Company had 1898 Company develop a BCA for this project, which also found the project not cost-effective.[854] Nevertheless, the Company identifies safety benefits that

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848 Case No. U-21297, Dec. 1, 2023, Order, p. 103.

849 *Id.* at 103-104.

850 Ex A-12 Sch B5.4 p. 15 line 64.

851 Deol Direct, 5 TR 1191-1204.

852 *Id* at 1193-7.

853 *Id* at 1198-1200.

854 *Id* at 1201-2; Ex A-23 Sch M13.

redeem undergrounding, including removing hazards of 4.8kV ungrounded delta system, and plans to consider additional undergrounding pilot projects.[855]

AG-MN witness Alvarez opposed the continuation of this pilot.[856] He acknowledged the potential for safety benefits from undergrounding but it is prohibitively expensive. The Buffalo project comes at a cost of $37,908.50 per customer.[857] He noted the benefit-cost ratio of DTE's 2 undergrounding pilots are in line with other assessments of undergrounding, and additional pilots are unlikely to deliver different results. He recommended disallowing increased 2024 spending above what was approved in U-21297 ($15.64 million) and all 2025 spending.

In rebuttal, Mr. Deol supported the Company's proposed spending levels.[858] The rebuttal reiterates DTE's interest in undergrounding and that of other parties. He agreed with Mr. Stephens that underground lines are still subject to reliability and safety risks associated with excavation, which may be mitigated in part with municipal permits, though he asserted Company lines are designed to withstand flooding.[859] He maintained that undergrounding is an alternative and does provide customer and Company benefits, which is why the Company is proceeding with additional pilots. The rebuttal never responded to Mr. Stephens' concerns about the extremely high cost of undergrounding and the negative benefit-cost ratio, even per the 1898 Company assessments of both DTE pilots. DTE is promising similar safety and reliability benefits from ETTP, Hardening, PTTM, Conversion, CEMI, and other investments, which – while not proven cost-effective – are a deep discount bargain relative to undergrounding. DTE ratepayers have already funded

[855] Deol Direct, 5 TR 1203-04.

[856] Stephens Direct, 6 TR 4025-6.

[857] *Id.* at 4026.

[858] Deol Rebuttal, 5 TR 1263-6.

[859] *Id* at 1265-6.

undergrounding pilot, they produce insufficient benefit to justify continuation. The Commission should adopt Mr. Stephens' recommendation and eliminate this pilot.

G. Business Charger Program (Reserved)

H. EV Sales Forecast

MNSC incorporates by reference its discussion on EV-related issues from the **Rate Base** section above discussing capital investments.

I. TEP Charger Uptime/Destination Charging (Reserved)

J. TEP Residential Rebate Program (Reserved)

K. Public Level 2 Chargers (Reserved)

X. FUTURE RATE CASES, FURTHER STUDY, OTHER

A. Benefit Cost Analysis (BCA) (Reserved)

B. DGP (Reserved)

C. Affordability – see Low Income Programs discussion above.

D. Distribution Generation (Reserved)

E. Cost of Service and Rate Design[860]

1. <u>Cost of Service and Rate Design: The Commission should direct DTE to file an analysis in its next rate case of the seasonality of distribution cost causation, and to evaluate potential residential sub-classes for multi-family homes and electric heating.</u>

CUB-MEC witness Graham Woolley and CUB-MN witness David Gard presented information in this case regarding transformer aging as it relates to distribution cost causation,;

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[860] MNSC believes that the following portions of the record are relevant to these issues:

- Revised Direct Testimony of MNSC witness Douglas Jester, 6 TR 3795-3800;
- Direct Testimony of MNSC witness David Gard, 6 TR 3819-31 and listed exhibits;
- Direct Testimony of MNSC witness Graham Woolley, 6 TR 3834-54 and listed exhibits;

and differences in energy and demand profiles between single-family residential customers, multi-family customers, and electric heating customers. Based on this information, MNSC witness Douglas Jester testified that the Commission should direct DTE in its next rate case to evaluate the seasonality of distribution cost causation, and to evaluate potential residential sub-classes for multi-family homes and electric heating.[861]

CUB-MEC witness Woolley explained that nominal transformer ratings do not capture the physics of transformer aging, and so those ratings should not be the sole basis for transformer sizing decisions.[862] Based on modeling he presents, Mr. Woolley explains that transformer aging occurs almost entirely in summer months, while almost none happens in the winter.[863] Mr. Woolley's findings have implications for cost causation, and also mean that increasing load during winter months is unlikely to compromise the health of existing transformers, which are typically sized to accommodate summer peaks.[864] Based in part on Mr. Woolley's analysis, CUB-MN witness David Gard modeled the effects of potential levels of building electrification on residential hourly load.[865] He found that the distribution transformer network's existing design capacity could accommodate a building electrification adoption level of 44%.[866]

- Rebuttal Testimony of DTE witness Satvir Deol, 5 TR 1268-9;
- Rebuttal Testimony of DTE witness Aaron Willis, 6 TR 2620-6;
- Rebuttal Testimony of DTE witness Habeeb Maroun, 6 TR 2791-5;
- Rebuttal Testimony of ABATE witness James Dauphinais, 6 TR 3415-6.

[861] MNSC witness Jester's original direct testimony also discussed production cost allocation. However, that section of his testimony was subsequently withdrawn after rebuttal and revised direct testimony was filed. Rebuttal testimony by ABATE witness Dauphinais and DTE witness Maroun to Jester's testimony on production cost allocation is now moot.

[862] Woolley Direct, 6 TR 3834-54.

[863] *Id*.

[864] *Id*.

[865] Gard Direct, 6 TR 3827-8.

[866] *Id*.

Relying on these analyses by witnesses Woolley and Gard, MNSC witness Jester testified that because aging of line transformers occurs almost exclusively occurs during the summer months, utilization of the effective capacity of the distribution system is highly seasonal.[867] That is true "both because nominal loads are lower in non-summer seasons but also because transformer effective rating is higher when ambient temperatures are lower."[868] Because transformer capacity 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" – and so distribution costs should be allocated seasonally.[869] Jester recommended 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."[870]

In rebuttal, DTE witness Satvir Deol responded that "[t]hermal loading and ambient temperatures is only one of several factors including thru-faults and voltage impulses (switching surges, lightning, etc.) that can lead to transformer aging."[871] He acknowledged that "a transformer experiences 'accelerated' aging in extreme heat due to high load and ambient temperature," but noted that "if a transformer were to be fully loaded for 1 year in a cold/winter climate, it would have 1 year worth of life of the transformer consumed as well."[872] While Mr. Deol's description of other factors in transformer aging is acknowledged, he appeared to at least partially agree with Mr. Woolley that the high load and warm temperatures found in summer combine to cause much greater aging than other times of year.

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[867] Jester Direct, 6 TR 3795.

[868] *Id*.

[869] *Id*. at 3796.

[870] *Id*. at 3800.

[871] Deol Rebuttal, 5 TR 1268-9.

[872] *Id*.

DTE witness Habeeb Maroun responded that "[t]he suggestion by Witness Jester for the Company to perform an analysis on seasonality and distribution costs for the upcoming rate case is deemed insufficiently detailed."[873] Mr. Maroun questioned whether Jester sought "an independent study or a supplemental COSS to assess the seasonality of distribution cost causation."[874] Mr. Maroun also questioned whether the benefits of incorporating seasonality into distribution cost allocation would outweigh the risk of complicating the COSS model further.[875] He concluded that the increased complexity and absence of clearly defined benefits "lead to the conclusion that this recommendation should not be considered."[876]

Mr. Maroun's dismissal of the benefits of evaluating distribution cost causation seasonally appears not to have considered Mr. Jester's testimony about the benefits of allocating distribution costs seasonally in combination with creating residential subclasses for multi-family and electric heating customers. This section discusses those topics further below.

ABATE witness James Dauphinais responded that "just because the loss of life of a distribution transformer may be higher in certain seasons than others, it does not mean the allocation of all distribution costs should be based on seasonal utilization even if distribution equipment ratings are sensitive to ambient temperature."[877] However, "given MNSC witness Jester has not requested the Commission to find in this proceeding that distribution rates be based on seasonal utilization, only that the Commission require certain information be filed by DTE in its

[873] Maroun Rebuttal, 5 TR 2781.

[874] *Id*. at 2793.

[875] *Id*. at 2794.

[876] *Id*. at 2794-95.

[877] Dauphinais Rebuttal, 6 TR 3416.

next rate case filing," Mr. Dauphinais simply reserved ABATE's right to respond to such a future proposal.[878]

In addition to the seasonality of distribution costs, CUB-MN witness Gard also modeled energy and demand profiles for certain subsets of residential customers using NREL data.[879] He modeled profiles for occupants of single-family vs. multi-family dwellings, and users of electric heating.[880] The single-family load profile shape demonstrated higher summer peaks and less wintertime load than the multi-family load profile shape.[881] He concluded that single-family and multi-family residential customers have meaningfully different COS characteristics, but the unique multi-family load profile shape is largely hidden within DTE's residential customer class.[882]

Mr. Gard also evaluated energy and demand profiles for various levels of building electrification. He testified that building electrification is expected to increase in Southeast Michigan in the years ahead for a number of reasons he outlined in detail.[883] Mr. Gard created an Excel spreadsheet model to simulate the effects of building electrification and other measures on residential hourly load.[884] He found that "[a]s building electrification increases, much of the additional load occurs during the winter heating season with the annual peak eventually shifting to winter."[885] Adding electric vehicles "further increases load throughout the year with the general shape of the profile still being largely determined by the amount of building electrification."[886]

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[878] *Id*.

[879] Gard Direct, 6 TR 3824.

[880] *Id*.

[881] *Id*.

[882] *Id*. at 3825.

[883] *Id*. at 3826.

[884] *Id*. at 3827. Ex CUB-24 discusses details of the model.

[885] *Id*. at 3829.

[886] *Id*.

Critical peaks in colder months tend to increase with building electrification, while those in warmer months tend to decrease slightly – due to simulated building envelope upgrades accompanying electrification having the effect of reducing air conditioning load.[887]

Mr. Gard concluded that as building electrification and EV charging increase, load profiles will change.[888] He said that "[i]t is important not to discourage these choices with rate designs that do not accurately reflect COS."[889] To continue "applying identical COS factors, based on a summer peak, to both non-electric and electric heating customers" will overcharge electric heating customers, "and the benefit of their annual peak occurring during winter when more system capacity is available will not be fully captured."[890]

MNSC witness Jester testified that Mr. Gard's analysis "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."[891] Jester reiterated Mr. Gard's recommendation that these different profiles warrant separate residential customer rate classes in the future, and recommended 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."[892]

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[887] *Id*.

[888] *Id*.

[889] *Id*. at 3830.

[890] *Id*.

[891] Jester Direct, 6 TR 3796.

[892] *Id*.

Jester identified three benefits from the combination of allocating distribution costs seasonally and adding multi-family and electric heating sub-classes to the residential class.

"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."[893] He noted that multi-family residential customers are almost certainly subsidizing single-family residential customers; and customers with electric heating are subsidizing customers that heat with fossil fuels.[894] The problem is exacerbated because electric heating is much more common in multi-family housing than single-family housing.[895] "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."[896] Therefore, "separating these classes to determine cost of service and construct different rate schedules could significantly reduce current inequities in electric utility bills."[897]

Second, Jester testified that the identified changes in rate design would provide constructive 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."[898]

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[893] *Id*. at 3798.

[894] *Id*.

[895] *Id*.

[896] *Id*.

[897] *Id*.

[898] *Id*.

Third, Jester opined that "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."[899]

While the potential benefits of the recommended changes in rate design and cost allocation are substantial, Jester noted that he does not recommend that they be made in this case. Rather, he recommended 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; "and 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."[900]

In rebuttal, DTE witness Aaron Willis opposed all of Jester's recommendations, but Mr. Willis's reasons are unavailing.[901] First, Mr. Willis claimed that as a matter of standard business practice DTE does not know which residential customers are single family and which are multi-family, and which customers use electric heating (unless they are on the existing space heating rate).[902] But whether DTE has this knowledge now is not the point. The point is that the analysis just described warrants investigating these issues.

As a large, sophisticated utility, DTE has sufficient expertise to investigate these issues using sampling techniques. Certainly, the Commission can take notice that DTE demonstrates proficient use of similar techniques for EWR program investment decisions. A good place to start is whether customer addresses contain an apartment or unit number, or just a street number.

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[899] *Id*. at 3799.

[900] *Id*. at 3799-80.

[901] Willis Rebuttal, 6 TR 2620-6.

[902] *Id*. at 2621.

Next, Mr. Willis presents a table of peak load characteristics by residential usage levels that he claims to illustrate that there is no specific significance to the single family, multi-family, or electric heating designations when it comes to peak behavior characteristics.[903] However, in discovery Mr. Willis acknowledged that his table "supports no position on whether or not there is a 'meaningful difference in the cost to serve' single v multifamily households."[904] He further acknowledged that his table "supports no position on whether or not there is a 'meaningful difference in the cost to serve' households with and without electric space heating."[905]

Mr. Willis also characterized the NREL data as inapplicable.[906] However, to support his argument, he merely quotes a line from the first page of the NREL ResStock Analysis Tool website.[907] The website shows many other uses of NREL's tool, including ones consistent with Mr. Gard's analysis.

Mr. Willis also argues that Mr. Gard's analysis "ignores other factors that could impact load shapes."[908] While that may or may not be true, witnesses Gard and Jester clearly stated multiple times that their analysis is not conclusive but rather is enough evidence to warrant further investigation.

Mr. Willis also argues that DTE "agrees with the overall concept of rate-schedule nonproliferation and suggests it be applied as a general practice."[909] However, in his direct testimony Jester noted that while adding multi-family and electric heating sub-classes to the

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903 *Id*. at 2622-23, Table 1.

904 Ex MEC-125, p. 2, discovery response MNSCDE-19.b.

905 *Id*., p. 3, sub-part 19.c.

906 Willis Rebuttal, 6 TR 2623.

907 *Id*.

908 *Id*. at 2624.

909 *Id*.

residential class will add some complexity to the COSS, "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."[910] Query how Mr. Willis knows without doing the analysis that DTE's existing set of rate schedules is exactly the right number to reflect cost of service and should never be changed again.

Finally, Mr. Willis states that DTE "currently serves a portion of customers on Rate Schedule D2, which is an entirely voluntary base service for customers with electric space heating" that DTE closed to new enrollments in 2015.[911] But as noted, Mr. Gard described the current rapid growth of modern heating electrification and active public policy around building electrification.[912] In light of the market and policy changes Mr. Gard describes, Mr. Willis's refusal to consider even studying whether changes should be made to cost allocation and rate design to accommodate these new developments is hard to understand.

In sum, the analyses by witnesses Woolley and Gard, and the testimony by witness Jester, present evidence warranting further study of the role of seasonality in distribution cost causation, and whether rate design currently reflects the cost responsibility of residential customers who use electric heating or reside in multi-family dwellings (or both). Mr. Jester's recommendations are well-founded and DTE's arguments for ignoring these issues a while longer are unavailing. The Commission should direct DTE in its next rate case to conduct and file the analyses recommended by MNSC.

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[910] Jester Direct, 6 TR 3796-97.

[911] Willis Rebuttal, 6 TR 2625.

[912] Gard Direct, 6 TR 3826.

F. Cost of Service Study (see section above)

G. Behind-the-Meter Battery Storage (Reserved)

H. Reliability Performance & Capital Investment (Reserved)

I. Geo-Targeted Incentives for Customer-Owned DG Systems (Reserved)

J. Critical Peak Rebate Program (Reserved)

K. 275 MW of BESS Capacity (Reserved)

L. Nanogrids and Microgrids (Reserved)

M. Outage Credits (Reserved)

N. Tree Trimming

MNSC incorporates by reference its briefing above in the *Rate Base* section opposing DTE's practice of capitalizing vegetation removal expenses when incurred in the process of distribution strategic capital projects.

O. Streetlighting (Reserved)

P. EV Programs – Analysis

MNSC incorporates by reference its discussion on EV-related issues from the **Rate Base** section above discussing capital investments.

Q. IT (Reserved)

R. Contribution in Aid of Construction (CIAC)[913]

On behalf of CUB, MEC, and NRDC, witness Denzler addressed the Company's proposal to update its CIAC rates.[914] He testified in support of keeping CIAC accurate and relevant in part

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[913] MNSC believes the record on this issue is as follows:

- Direct Testimony of DTE witness Brian L. Hill, 6 TR 3056-8; Rebuttal Testimony of Mr. Hill, 6 TR 3090-1;
- Direct Testimony of CUB, MEC & NRDC witness Joshua W. Denzler, 6 TR 3778-9.

[914] Denzler Direct, 6 TR 3778-9.

so that business customers pay their fair share of new business costs. He recommended the Commission order DTE in the next rate case to a report detailing the impact of the CIAC changes, including a review of new business construction costs and CIAC received, with comparison to historic and projections of future business construction costs and CIAC. He recommended regular review of CIAC costs – preferably every other year – to prevent CIAC lagging construction costs.

Company witness Hill opposed the recommendation.[915] Mr. Hill noted the information is already available in Exhibit A-12 Schedule B5.4 filed with the rate case. The information provided in Exhibit A-12 Schedule B5.4 provides none of the relevant information needed to ensure CIAC stays up to date with actual construction costs. That Exhibit shows the total dollars in CIAC for categories of projects – there is no way a reader can understand whether the amount of CIAC contributed for any project is accurate and reflects construction costs. The rebuttal is non-responsive and unhelpful. The Commission should direct the Company to provide updated CIAC costs on a biannual basis to ensure ratepayers are not subsidizing new construction.

[915] Hill Rebuttal, 6 TR 3091.

XI. INFRASTRUCTURE RECOVERY MECHANISM (IRM)

A. The Commission should deny DTE's request to extend the IRM and disallow the Company's enormous increases in IRM spending.[916]

In the last DTE Electric rate case, U-21297, the Company proposed a three-year IRM for the years 2024 through 2026, with total capital spending of $533 million.[917] The Commission approved a two-year IRM instead, with a total of $352 million in spending.[918] The Commission determined that limiting approval to the first two years would allow DTE to move forward with the IRM without precluding incorporation of results from the pending distribution audit in Case No. U-21305 and the performance-based ratemaking (PBR) docket in Case No. U-21400.[919]

But rather than accept the Commission's direction, DTE has come back in this case to propose an extension of the IRM through 2027 and enormous increases in IRM spending – up to *$1.7 billion* – prior to completion of the distribution audit and PBR evaluation.[920] DTE characterizes this massive expansion as a thoughtful and collaborative plan to benefit customers.[921] However, DTE's internal communications reveal a slapdash proposal the Company threw together

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[916] MNSC believes that the following portions of the record are relevant to these issues:

- Revised Direct Testimony of DTE witness Neal Foley, 2 TR 113-128; Rebuttal Testimony of Mr. Foley, 2 TR 151-63; Foley Cross Exam, 2 TR 187-277;
- Ex A-33, Schedule X1;
- Direct Testimony of Staff witness Nicholas Evans, 6 TR 5232-7;
- Direct Testimony of AG-MNSC joint witness Paul Alvarez, 6 TR 3943-7;
- Exhibits MEC-23 through -27;
- Direct Testimony of ABATE witness James R. Dauphinais, 6 Tr 3380-2;
- Direct Testimony of Walmart, Inc witness Lisa V. Perry, 6 Tr 4736-40.

MNSC notes that other DTE witnesses address specifics related to IRM programs, but those specifics are addressed where relevant in other sections of this brief. Further, MNSC is not challenging the accuracy of the calculation of IRM revenue requirements or surcharges.

[917] Case No. U-21297, Exhibit A-33, Schedule X1 and Table 1 of Mr. Foley's direct in that case.

[918] Foley Cross, 2 TR 192.

[919] Case No. U-21297, December 1, 2023, Order, p. 289.

[920] Foley Cross, 2 TR 195.

[921] See for example, Foley Direct, 2 TR 126-8; Foley Cross, 2 TR 195.

hastily. DTE did so in an attempt to establish the IRM as the "new normal," and eventually ramp up spending so much that the Company can avoid rate cases.[922] DTE Electric's President, Matthew Paul, directed the team to propose the highest spending amounts possible that would still pass the "smell test."[923]

The Commission should disapprove DTE's excessive expansion and extension of the IRM because the proposal disregards the Commission's own direction in U-21297. In addition to DTE's failure to support specific spending programs as discussed in the distribution capital section of this brief, above, the Commission should also disapprove DTE's proposal because it is not supported by substantial evidence, and the Company has not demonstrated it is reasonable, prudent, or in the best interest of customers.

This brief will discuss: (1) the Order in Case No. U-21297; (2) DTE's proposed expansion and extension of the IRM in this case; (3) the evidence showing how DTE decided to disregard the U-21297 Order and instead put forward the overreaching proposal in this case; and (4) the universal opposition to DTE's proposal by other parties.

1. Order regarding the IRM in U-21297.

In Case No. U-21297, DTE proposed a three-year IRM for the years 2024 through 2026.[924] The ALJ recommended disapproval of the IRM as premature.[925] The Commission disagreed in part. The Commission found that "there is value in the company's proposal," but also found the

[922] Ex MEC-25, discovery response MNSCDE-18.2a, p. 13 (establishing the IRM as "new normal"); Ex MEC-26, discovery response MNSCDE-18.2a, p. 9 ("grow it to the point where we can stay out of rate cases").

[923] Ex MEC-26, discovery response MNSCDE-18.2a, p. 28 ("make sure it passes smell test…").

[924] Case No. U-21297, Dec. 1, 2023, Order, p. 284.

[925] *Id*. at 285.

need for “some limitations.”[926] The Commission approved two years for the IRM instead of three, to allow the PBR and distribution audit processes to conclude before considering what to do next:

> In addition, the Commission finds that approval is limited to Plan Years 1 and 2. As noted on the record, there is ongoing discussion regarding PBR in Case No. U-21400 and an ongoing audit in Case No. U-21305. Therefore, the Commission finds that limiting the approval to the first two years will allow the company to move forward with the IRM without precluding the incorporation of any potential insights gained from those proceedings to better inform the potential continuation of the IRM.[927]

The Commission approved about $62 million in IRP spending for 2024 and about $290 million in 2025, for a total of $352 million.[928]

2. <u>DTE has not provided substantial evidence to support the reasonableness, prudence, or need for its proposed expansion and extension of the IRM</u>.

DTE witness Neal Foley sponsors the Company’s proposal to expand and extend the IRM in this case.[929] Mr. Foley proposes on behalf DTE to extend the IRM another two years through 2026 and 2027.[930] That is a year longer than the proposal in U-21297 that the Commission curtailed. Mr. Foley also proposes to add the Pole Top Maintenance and Modernization (PTMM) program to the IRM, and to expand the scope of what was previously labeled “4.8 kV Circuit Automation” to a broader program called “Distribution Automation.”[931]

Through Mr. Foley’s testimony, DTE also requests that the Commission authorize large increases in pre-approved IRM spending. DTE requests pre-approval for $530 million in 2026,

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926 *Id*. at 289.

927 *Id.*

928 *Id*. at 291.

929 Foley Direct, 2 TR 118-9.

930 *Id*.

931 *Id*.

and another $720 million in 2027 – for a total of $1.25 billion in additional IRM spending.[932] DTE also proposes additional spending in 2025:

- $125.6 million on Distribution Automation;
- $121 million on PTMM;
- $125 million on 4.8kV Hardening; and
- $62.5 million on the Frequent Outage Program (CEMI).[933]

This increased spending for 2025 totals about $434 million. It brings the total additional IRM spending to around $1.7 billion.[934]

No projects have been identified yet for 2026 and 2027.[935] For 2025, DTE recently filed its annual IRM plan.[936] The 2025 IRM plan identifies projects for the $290 million approved for 2025 in U-21297, but no projects for the additional $434 million in 2025 spending that the Company proposes in this case.[937] Mr. Foley said on cross that if the Commission approves the additional $410 million, DTE would file an amended plan "as quickly as we could" to add projects to take up that additional spending.[938]

In his direct testimony, Mr. Foley provides very little affirmative support for the enormous ramp-up in IRM spending. He provides no support whatsoever for the reasonableness, prudence, or necessity of the large increases in 2026 and 2027, compared to the amounts approved for 2024 and 2025 in U-21297. He only says that the amounts proposed in this case for 2026 are similar to

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932 Foley Direct, 2 TR 119, Table 1; Foley Cross, 2 TR 193.

933 Foley Direct, 2 TR 128.

934 Foley Cross, 2 TR 195.

935 Foley Cross, 2 TR 193-4.

936 Ex MEC-24, IRM Plan for 2025.

937 Foley Cross, 2 TR 262-3.

938 *Id*.

the amounts proposed for 2026 in U-21297 – ignoring the fact that the Commission did not approve the amounts proposed for 2026 in that case.[939] And he says nothing at all to support the even larger increase in spending for 2027. As to the proposed increase in 2025, Mr. Foley only says that it would "increase the benefits associated with the IRM" by increasing "the certainty of investment of this incremental IRM capital for its intended purpose, with any under-investment triggering a refund to customers."[940] However, he also acknowledged on cross that the IRM benefits DTE by providing certainty of timely recovery of costs.[941]

Similarly, Mr. Foley offers only the thinnest and vaguest support for extending the IRM through 2026 and 2027 before the conclusions of the PBR and distribution audit processes. He says that "stopping and restarting of the IRM and its associated processes could lead to inefficiencies and reduce the ability to improve upon the process through stakeholder feedback;" while extending it "will ensure that the customer and stakeholder benefits realized through the IRM do not lapse."[942] Mr. Foley "acknowledges" the Commission's statement in U-21297 that the conclusions of the PBR and audit processes are needed to better inform the potential continuation of the IRM.[943] And he outlines the next steps for the PBR and audit processes in some detail.[944] But Mr. Foley never explains why the Commission should reverse its prior finding, and determine that preventing a lapse in the IRM is now more important than having the results of the PBR and audit processes to inform its decisions about continuing the IRM beyond 2025.

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[939] Foley Direct, 2 TR 120.

[940] Foley Direct, 2 TR 127.

[941] Foley Cross, 2 TR 203.

[942] *Id*. at 121.

[943] *Id*.

[944] *Id*. at 122-6.

3. Evidence of how DTE planned the IRM expansion and extension confirms that the Company threw the proposal together in a hasty and slapdash manner.

On cross, Mr. Foley acknowledged that DTE is proposing $1.66 billion of additional IRM spending in this case, and that this figure is a five-fold increase over what the Commission approved in U-21297.[945] When asked where these new numbers came from, Mr. Foley responded:

> Well, these numbers were essentially developed in collaboration with multiple groups here at the Company, specifically the distribution operations capital planning team and project management office teams, so they were sort of collaboratively developed largely with those teams, in addition to others such as regulatory affairs.[946]

However, internal presentations and emails show the opposite. DTE initially planned to propose a one-year extension for 2026, at the spending level the Commission approved for 2025 in U-21297. Then, for unexplained reasons, the Company reversed course and decided to push for two years and higher spending amounts. The spending amounts for 2026 and 2027 snowballed quickly over just two weeks, until DTE Electric's President outlined the current proposal by email following a meeting between himself and DTE Energy's head of Regulatory Affairs. Then, mere days before filing this case, DTE hastily pulled together increased spending amounts to propose for 2025. The evidence discussed next shows that the IRM expansion and extension is not a thoughtful proposal backed by careful analysis. Rather, it is a slapdash proposal thrown together to maximize spending levels and steamroll the Commission's expressed intent to use the results of the audit and PBR processes to inform further IRM decisions.

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[945] Foley Cross, 2 TR 195.

[946] Foley Cross, 2 TR 195.

On December 15, 2023, two weeks after the Order in U-21297, Mr. Foley outlined "options for IRM in the upcoming rate case:"[947]

- Option 1 was to simply follow the directive in U-21297, which would "[a]llow time to establish IRM and begin new annual processes without having to already argue for changes."[948]
    - Mr. Foley did not favor this option because "stopping/starting could challenge establishing IRM as 'new normal.'"[949]
- Option 2 was a simple extension of the IRM through 2026.[950]
    - "Cons" for this option were that it "does not meaningfully grow IRM scope, investment levels, or 3-year duration;" and "does not address PBR [or] DO audit."[951]
- Option 3 was extending the IRM through 2026 or 2027 at increased spending levels and with additional programs. [952] As conceived at that time, Option 3 was to include a proposed PBR mechanism.[953]
    - Pros for Option 3 were that it "allows IRM scope, investment levels, and/or duration to grow" and the proposed PBR mechanism "mitigates Commission and intervenor concerns about not having PBR."[954]

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[947] Ex MEC-25, discovery response MNSCDE-18.2a, p. 13.

[948] *Id*.

[949] *Id*.

[950] *Id*.

[951] *Id*.

[952] *Id*.

[953] *Id*.

[954] *Id*.

- Cons were that it "does not address Commission's concerns about ongoing Distribution Audit activities" and "would propose PBR before separate case is complete."[955]

DTE decided to move forward with a simple one-year extension of the IRM.[956] Then, on January 23, 2024, the Company abruptly decided to propose an expansion of the IRM, and without a PBR proposal.[957] DTE witness Foley – the sponsor of the IRM proposal in this case – did not know why DTE reversed course or who made the decision to extend and expand the IRM.[958] Nor did Mr. Foley know why DTE dropped the PBR component from its proposal.[959]

Mr. Foley created the first draft of the new proposal on January 29, 2024, for a one-year extension to 2026 with additional spending of $247 million in 2025 and $74 million over the new 2025 amount in 2026.[960] He sent it to VP of Regulatory Affairs Marco Bruzzano, and in an exchange of emails over the next seven minutes, they increased the 2026 spend by $48 million.[961] Mr. Bruzzano emailed, "I like it…would be pretty awesome."[962] Mr. Foley indicated that they "[c]ould increase it more if we wanted to."[963]

One guidepost articulated by Mr. Foley was to grow spending for programs like 4.8 kV Conversions and Subtransmission Redesign and Rebuild "by a modest amount like 20% to show

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[955] *Id*.

[956] Foley Cross, 2 TR 214-5.

[957] *Id* at 214-5; Ex MEC-26, p. 47.

[958] *Id* at 216.

[959] *Id* at 216.

[960] Ex MEC-26, p. 39.

[961] Ex MEC-26, pp. 38-39; Foley Cross, 2 TR 225.

[962] Ex MEC-26, p. 38.

[963] *Id*.

growth, but not as severe as what's currently in the 2026 capital plan."[964] On cross, Mr. Foley denied that he was using the word "severe" literally – meaning bad, undesirable, or harsh.[965]

When Mr. Foley emailed the Distribution team to let them know a proposal was coming, DTE witness Jamie Kryscynski asked if the target for expanded spending would be in the $50 million range.[966] In fact, it was in the $325 million range – with $537 million of spending in 2025, and $659 million in 2026.[967] When asked if that was a lot more than the $50 million that the Distribution team was expecting, Mr. Foley demurred.[968]

Contemporaneous emails indicated that, in addition to the spending increase, DTE was planning to file an alternative proposal that would be a "simple extension" through 2026 at the spending amounts approved in U-21297.[969] DTE subsequently dropped the simple extension alternative – but Mr. Foley did not know who made that decision, either.[970]

Over the next few days, the proposed spending continued to increase and the length of the extension grew from one year to two years. On February 9, 2024, DTE Electric President Matthew Paul emailed the team:[971]

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964 Ex MEC-26, p. 39.

965 Foley Cross, 2 TR 223.

966 Ex MEC-26, p. 44.

967 Ex MEC-25, p. 10; Foley Cross, 2 TR 222.

968 Foley Cross, 2 TR 221-2.

969 Ex MEC-26, p. 46.

970 Foley Cross, 2 TR 220-1.

971 Ex MEC-26, discovery response MNSCDE-18.2b, p. 28.

From: Matthew T Paul <matthew.paul@dteenergy.com>
Sent: Friday, February 9, 2024 3:08 PM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Subject: RE: Updated IRM expansion proposal for review

Neal –
Marco and I just talked and aligned on the following:

1. Ramp at something like 290, 530, 700-720
2. Introduce PTMM in 2026 as a bucket (maybe at 70-75M level)
3. Attempt to treat the buckets (automation, PTMM, subtrans, conversions, other) consistently, i.e., growing at 20% or whatever (note – because hardening sunsets, we were not thinking to including it).
4. Final connection with key team members to make sure it passes smell test for them

Happy to entertain feedback from the team if there are significant concerns, but trying to nail this down today or Monday.
Thanks –
Matt.

Mr. Paul's email reflects the proposal DTE ultimately made in this case for the years 2026 and 2027: a two-year extension with $1.25 billion in additional spending compared to what the Commission approved in U-21297. The program spends would increase by 20% per year ("or whatever") to stay within Mr. Foley's guidepost of not being too severe. Mr. Paul directed a final connection with key team members – presumably in distribution capital groups – to make sure it passes the "smell test."

In response to an inquiry from Mr. Paul's team as they were preparing to present the proposal to DTE Energy leadership, Mr. Foley indicated: "We really haven't set a 2030 target for the IRM beyond continuing to grow it to the point where we can stay out of rate cases."[972] Mr. Foley added that "I think it's certainly our aspiration to grow the IRM beyond $720M, just haven't set a specific target."[973]

The emails revealed an internal disagreement about whether to include the PTMM program in the IRM. DTE witness Morgan Elliott Andahazy – the distribution capital witness for PTMM

[972] Ex MEC-26, p. 9.

[973] *Id.*

in this case – apparently opposed including the program.[974] But DTE witness Kryscynski emailed on February 9:

> As an FYI if it impacts the final decision, I had an interview this week with the auditors. I got a VERY strong impression that they are going to come out in firm support of an expanded PTMM program. I think we might have some wind in the PTMM sails post audit report.[975]

Two weeks later, Mr. Kryscynski emailed again:

> I had another meeting with the auditors yesterday and they said that the two programs they feel are highest priority are 1) Tree Trim and 2) PTMM. There is very little chance that the audit report doesn't come out very strongly in favor of increased investment in this area.[976]

On cross, Mr. Foley said he had no knowledge of why or how Mr. Kryscynski was getting advance information from the auditors about their conclusions.[977] In his cross exam, Mr. Kryscynski repeatedly denied remembering any specifics about his discussions of PTMM with the auditors or why he told the DTE team that the auditors were going to support the program.[978] Ultimately, Mr. Bruzzano made the decision to include PTMM in the IRM. He referenced Mr. Kryscynski's conversations with the auditors and a key meeting that apparently took place on February 15, 2024.[979] Both Mr. Foley and Mr. Kryscynski denied having any recollection of who the February 15 meeting was with, or what it was about.[980]

After settling on IRM programs and spends for the expansion/extension proposal in this case, on Sunday, March 17, 2024 – 11 days before filing this case – Mr. Bruzzano emailed the

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[974] Ex MEC-26, p. 22 ("sorry Morgan we couldn't keep PTM out!").

[975] Ex MEC-26, p. 27.

[976] Ex MEC-26, p. 18.

[977] Foley Cross, 2 TR 238-9.

[978] Kryscynski Cross, 3 TR 599-602.

[979] Ex MEC-26, p. 19.

[980] Foley Cross, 2 TR 246; Kryscynski Cross, 3 TR 599-600.

Executive Committee of DTE Energy to inform them that the team was working on a proposed increase in IRM spending for 2025, too.[981] The effort was apparently in response to "Jerry's request over the weekend"[982] – presumably DTE Energy CEO Jerry Norcia.

By mid-day on Monday, the team had agreed on the $434 million of additional 2025 spending presented in Mr. Foley's testimony.[983] Mr. Foley wrote that the additional dollars would bring total 2025 spending to $724 million, which would be "worth about $52M of revenue."[984] Everyone agreed that "it would be a significant stretch to increase much higher."[985]

In sum, the internal communications belie DTE's portrayal of the IRM as a carefully-crafted proposal intended to benefit ratepayers. To the contrary, DTE threw the two-year extension and spending increases together hastily, after abruptly abandoning a simple one-year proposal. The extension and spending increases are not driven by any reliability justification. Rather, they are targeted to establish the IRM as the "new normal" and "business as usual" – and to grow IRM spending as rapidly as possible to eventually stay out of rate cases. DTE added large amount of PTMM spending was added because Company officials believed they had inside information from the auditors about that program. The only apparent governing principles DTE employed as limits on the proposed IRM spending increases were that they not be "too severe" and that they pass the "smell test." Whether they actually pass these tests is for the Commission to judge.

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[981] Ex MEC-26, p. 8.

[982] Ex MEC-26, p. 6.

[983] Ex MEC-26, pp. 5-6.

[984] Ex MEC-26, p. 5.

[985] *Id*.

MNSC submits that this is no way to do business. Nor does it meet the requirements that rate requests be just and reasonable, and that proposals be based on substantial evidence.[986] Nor did DTE meet its burden of demonstrating that the IRM expansion and extension proposal is reasonable, prudent, or in the best interest of customers.[987] It is therefore not a surprise that the parties to this case universally oppose DTE's proposal. This brief will discuss their testimony next.

4. Universal opposition to DTE's proposal from other parties.

Staff witness Nicholas Evans testified that "Staff does not support extending the IRM through calendar years 2026 and 2027."[988] Consequently, he said, Staff does not support authorizing PTMM for IRM treatment, starting in 2026.[989] Mr. Evans also testified that Staff does not support the bevy of spending increases DTE proposed for 2025.[990] Mr. Evans reiterated the Commission's direction in the U-21297 Order limiting the IRM approval to two years to allow decisions on future proposals to be informed by the results of the PBR process and distribution audit.[991] Mr. Evans explained that from a process standpoint, stopping the IRM temporarily and then re-starting it later can be accommodated; and "it is better to pause the IRM for part of 2026 to allow for more efficient spending in 2026 and 2027 than to authorize in this rate case 2026 and 2027 IRM plans that may have already been rendered outdated by the Liberty audit report in U-21305 and a Commission order in U-21400 on financial incentives and disincentives."[992]

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[986] See MCL 460.557(4) ("The rates of an electric utility shall be just and reasonable…"); MCL 460.6a(1) ("The utility shall place in evidence facts relied upon to support the utility's petition or application to increase its rates and charges…").

[987] Case No. U-7484, Aug. 30, 1983, Order, p. 10; Case No. U-8030-R, July 9, 1987, Order, pp. 16-17.

[988] Evans Direct, 6 TR 5234.

[989] *Id*.

[990] *Id*. at 5235.

[991] *Id*.

[992] *Id*. at 5237.

In his rebuttal, DTE witness Foley protested that approving a two-year extension with higher spends for specified programs would not, in fact, lock the Company into specific spending amounts – because DTE could adjust its IRM plans later based on the results of the audit and PBR processes.[993] On cross, however, he acknowledged that if the Commission approves DTE's proposal now, nothing would require the Company go amend its IRM plans based on the results of the PBR process and distribution audit.[994]

Mr. Foley also asserted in rebuttal that a gap between IRM approvals "would lead to inefficiencies in the process" of submitting and reviewing IRM plans.[995] However, the presentations and emails discussed above document that DTE's true concern about stopping and re-starting the IRM was that it could interfere with the Company's strategy of establishing the IRM as "business as usual" and the "new normal." This tactical interest of DTE's hardly outweighs the Commission's interest in having the benefit of the PBR and audit results before making further decisions on the IRM.

Finally, Mr. Foley stated that "if the Commission does not find it appropriate to approve a two-year extension at the proposed investment levels," then DTE requests approval of a one-year extension without spending increases.[996] Recall that this is the same proposal that DTE initially planned to make but then abandoned without explanation in late January 2024. The Commission should not indulge DTE's ham-handed attempt to pivot at the end of this case. Rebuttal is not the time to change proposals or attempt to negotiate. The other parties have not had a chance to introduce their own testimony on the merits (or lack thereof) of a one-year extension at current

[993] Foley Rebuttal, 2 TR 154.

[994] Foley Cross, 2 TR 264-5.

[995] Foley Rebuttal, 2 TR 154-5.

[996] *Id* at 155.

spends. If such a proposal is satisfactory to DTE, the Company should have introduced it in its direct case as originally planned – instead of the overreaching moon shot the regulatory team talked themselves into in February and March.

Paul Alvarez, a joint witness for the Attorney General and MN, testified that a cost recovery rider like the IRM shifts capital spending risk from shareholders to customers, because the pre-approved capital expenditure amounts reduce the risk of disallowances to practically zero.[997] That risk shift encourages utilities to pursue much higher spending amounts and less beneficial projects.[998] Mr. Alvarez further explained that the IRM plan preview and reconciliation processes do not effectively counter this risk shift, because the burden falls on Staff and intervenors to counter the utility's spending – rather than falling on the utility to demonstrate the reasonableness and prudence of that spending.[999]

In rebuttal, DTE witness Foley first asserts that Mr. Alvarez made the same or similar arguments in U-21297, and that the Commission implicitly rejected those arguments when it approved the IRM in that case.[1000] However, as already discussed, in U-21297 the Commission did *not* approve DTE's proposal as presented. Rather, the Commission limited the IRM to two years and approved much lower spending levels than DTE is proposing here. Thus, Mr. Foley's argument that the Commission already rejected Mr. Alvarez's arguments by approving an IRM in U-21297 falls flat. The proposal the Commission approved in U-21297 was a far cry from DTE's proposal in this case. It is DTE – not the intervenors – who is seeking to overturn the status quo. If the Commission's IRM findings in U-21297 are sacrosanct, then DTE should not be seeking to

[997] Alvarez Direct, 6 TR 3943.

[998] *Id*. at 3944-5.

[999] *Id*. at 3947.

[1000] Foley Rebuttal, 2 TR 160-1.

multiply the IRM duration and spending far beyond what the Commission limited them to, and disregarding the Commission's direction to wait for the results of the PBR and audit processes before making decisions about future iterations of the IRM.

Mr. Foley also asserts that Mr. Alvarez's testimony that the IRM plan preview and reconciliation processes put the burden on intervenors to counter DTE's proposals "is unfounded."[1001] However, Mr. Foley offers nothing to support his argument other than asserting that DTE must provide a forum where intervenors can raise concerns with the annual IRM plan in advance and "then defend those investments in a contested reconciliation proceeding."[1002] Nothing in his testimony changes the fact that DTE is not obligated to act on any concerns raised by intervenors in the plan review; or that the pre-approval of program spend amounts shifts the burden of proof as a practical matter in the reconciliation. And as noted earlier, Mr. Foley acknowledged on cross that the IRM benefits DTE by providing certainty of recovery.[1003] That is the same thing in different words as what Mr. Alvarez said.

On this last point, it is illuminating to see how DTE discusses the reconciliation process internally. Commenting on a draft presentation about the IRM created by another DTE employee, Mr. Foley wrote: "For cost evaluation, I'm not sure we want to proactively talk too much about the reconciliation process is a time for intervenors to challenge our costs."[1004] Once again, DTE seems to be making one set of representations about the IRM to the Commission and parties in this case, while discussing the IRM internally in different terms.

[1001] Foley Rebuttal, 2 TR 161.

[1002] *Id*.

[1003] Foley Cross, 2 TR 203.

[1004] Ex MEC-26, p. 31.

In addition to Staff, the Attorney General, and MEC/NRDC, the following parties also opposed or proposed limiting the IRM:

- Direct Testimony of ABATE witness James R. Dauphinais, 6 Tr 3380-2;
- Direct Testimony of Walmart, Inc witness Lisa V. Perry, 6 Tr 4736-40.

In sum, the Commission should reject DTE's proposal to extend the IRM for two years and massively increase the pre-approved spending amounts. The Company's proposal is not reasonable, prudent, or in the best interest of ratepayers. It was thrown together in a rash and clutching manner, with no apparent organizing principle other than to get as much spending preapproved as the principals thought they could obtain from the Commission. It utterly disregards the Commission's attempt to balance objectives in U-21297 by limiting the IRM in duration until the outcome of the audit and PBR processes. And the other parties in this case universally oppose it – for good reasons that DTE has failed to counter.

XII. STORM RECOVERY COST SHARING MECHANISM (SRCSM)

A. The Commission should disapprove DTE's proposed Storm Recovery Cost Sharing Mechanism because it is not reasonable, prudent, or in the best interest of ratepayers.[1005]

DTE seeks approval of a Storm Recovery Cost Sharing Mechanism (SRCSM). Under the SCRSM, the Company would defer and recover 50% of the difference between approved and actual storm restoration expenses in years when DTE incurred higher actual expenses than approved; and would defer and credit to customers 50% of the difference between approved and actual storm restoration expenses in years when DTE incurred lower actual expenses than the

[1005] MNSC believes that the following portions of the record are relevant to these issues:

- Direct Testimony of DTE witness Neal Foley, 2 TR 128-36; Rebuttal Testimony of Mr. Foley, 2 TR 163-72.
- Direct Testimony of CUB-MN witness Joshua Denzler, 6 TR 3769-74.
- Direct Testimony of Staff witness Jessica Duell, 6 TR 5148-9.
- Direct Testimony of Ann Arbor witness Melissa Stults, 6 TR 4259-63.

approved level. The Commission should disapprove DTE's proposal because it is not reasonable, prudent, or in the best interest of ratepayers.

In Consumers Energy's last electric rate case, U-21389, Consumers proposed a storm cost sharing mechanism that it dubbed the Symmetric Performance Mechanism, or SPIM.[1006] Consumers proposed to return 90% of unspent storm restoration expenses below rate levels to customers, retaining the other 10%; and to recover 90% of storm restoration expenses above rate levels, foregoing the other 10%. The Commission disapproved the SPIM for several reasons:

- Consumers did not demonstrate "that the SPIM will sufficiently control service restoration expenses."
- Consumers failed to "specify a level of performance to be incentivized by the SPIM."
- The SPIM did not incentivize the company to reduce service restoration expenses more than 10% below that approved in rates.
- There was no evidence demonstrating that the 10% offset would adequately deter the company from passing through large cost increases to customers.
- Finally, the found that "approval of the mechanism is premature given the ongoing audit in Case No. U-21305."[1007]

In this case, DTE proposed that base rate storm restoration O&M expense be set based on a five-year trailing average of $64.5 million.[1008] Then the SRCSM would account for the difference between the authorized and actual expenses for each year. If actual storm restoration O&M expenses are less than projected, the Company would return 50% of the difference to customers

[1006] Case No. U-21389, March. 1, 2024, Order, p. 170.

[1007] *Id*. at 174-175.

[1008] Foley Direct, 2 TR 129.

by recording that amount as a regulatory liability.[1009] If actual storm restoration O&M expenses are more than projected, the Company would recover 50% of the difference from customers by recording that amount as a regulatory asset.[1010] The cumulative net regulatory asset would be addressed in DTE's next rate case.[1011]

Mr. Foley claimed that DTE's proposal is "responsive to the Commission's guidance in Case No. U-21389" because DTE is not proposing a 10% deadband like Consumers did.[1012] He asserted that the 50% cost or savings sharing provides DTE with a stronger incentive than Consumers' proposal did.[1013] Mr. Foley also disputed the need to wait for the distribution audit to move forward with a storm cost recovery mechanism.[1014] Mr. Foley did not address the Commission's expressed concern in U-21389 about the lack of a specified level of performance to be incentivized.

CUB-MN witness Joshua Denzler testified that DTE's proposal is bad for customers, because it "skews the share of risk significantly in favor of the Company, at the expense of ratepayers;" and it "creates a strong misalignment of incentives, when the Company's historical storm performance is already very poor."[1015] Denzler noted that the increased storm severity projected by DTE is are realized, costs are much more likely to exceed projections than to be below them – and so DTE is much more likely to collect additional expense from customers than to refund any expense to them.[1016]

[1009] *Id*. at 133.

[1010] *Id*.

[1011] *Id*.

[1012] *Id*. at 135.

[1013] *Id*.

[1014] *Id*. at 136.

[1015] Denzler Direct, 6 TR 3769.

[1016] *Id*. at 3769-70.

Denzler also reviewed the Company's poor storm performance.[1017] He noted that the SRCSM will incentivize DTE less than the current status in which DTE absorbs 100% of incremental expense over the amount approved in base rates.[1018] It could even create a financial incentive for the Company to extend the duration of Storm work because more work classified as Strom will be recovered from customers under the mechanism.[1019] Currently DTE has no standard, other than field crew judgement, on when to repair versus replace field assets.[1020] That scenario would then lead to undue increases in the level of storm expense included in the next rate case via the 5-year average.[1021] In light of the imbalance to the share of risk, the Company's poor Storm performance, and the likelihood for misaligned incentives, Denzler recommended that the Commission reject DTE's proposal.[1022]

Staff witness Jessica Duell also opposed DTE's proposal.[1023] She testified that the Commission should not be approve the SRCSM "because 1) Staff is supporting the full-service restoration expense for the test year; 2) the Commission rejected similar mechanisms in prior cases U-20963, U-20697, and U-21389; and 3) Staff would like to see results from the third-party audit to further determine cost savings in storm restoration expenses."[1024] She further noted: "Storms are also progressively getting worse each year. Customers may never see a benefit from the proposed storm restoration mechanism due to the Company spending over the requested amounts

[1017] *Id*. at 3770-2.

[1018] *Id*. at 3772.

[1019] *Id*.

[1020] *Id*.

[1021] *Id*. at 3773.

[1022] *Id*.

[1023] Duell Direct, 6 TR 5148-9.

[1024] *Id*. at 5149.

each year."[1025] Finally, and similar to CUB witness Denzler, Ms. Duell testified that "the way the Company currently recovers storm restoration expenses provides a stronger incentive to control costs than the Storm Restoration Cost Sharing Mechanism" because DTE "currently keeps 100% of savings, rather than 50%, and absorbs 100% of costs overages, rather than 50%. The Company's proposal dulls these incentives."[1026]

Ann Arbor witness Melissa Stults also opposed approval of the SRCSM, for reasons outlined in her testimony.[1027]

In his rebuttal, DTE witness Foley argued that Staff's support for the Company's projected test year storm restoration expense is not a reason to reject the SRCSM, because the SRCSM addresses variability of expenses.[1028] However, he seemed to miss the point that the new expense level provides DTE with greater revenue for storm restoration than before.

Mr. Foley also argued that the mechanisms the Commission rejected in Case Nos. U-20963, U-20697, and U-21389 were all cost trackers, rather than a cost sharing mechanism.[1029] But while he claimed that a cost tracker and a cost sharing mechanism are "fundamentally different," and the "fundamental difference provides sufficient justification for the Commission to assess the Company's proposal on its own merits," he provided no explanation for why those differences matter to the outcome on this issue.

Mr. Foley also disagreed with waiting for the distribution audit, claiming that the SRCSM would not "preclude the Company from using the findings of the Distribution Audit to pursue cost

[1025] *Id*.

[1026] *Id*.

[1027] Stults Direct, 6 TR 4259-63.

[1028] Foley Rebuttal, 2 TR 164.

[1029] *Id*. at 164-5.

savings in the future."[1030] However, he did not explain why DTE would be expected to do so if the Commission approved a sharing mechanism that removed much of the Company's incentive to find such savings.

Mr. Foley also disagreed with the point that "customers may never see a benefit from the proposed SRCSM."[1031] He asserted that "[t]he only way for such an outcome to occur would be if actual storm restoration costs were always above the projected level of costs;" and averred that this was "unlikely to occur" due to the "volatility of these costs."[1032] Here, Mr. Foley seemed to forget his own direct testimony that storm restoration expense and extreme climate events are trending upward.[1033] The SRCSM will charge or credit customers in the next rate case based on the overall net expense, not the ups or downs of a particular year.

In response to CUB-MN witness Denzler, Mr. Foley denied that the SRCSM would skew the share of risk in favor of DTE – claiming again that storm restoration expense is "uncertain and volatile."[1034] Here MNSC relies on the same response as the prior point: DTE claims these events and expenses are trending upward, and so sharing risks with customers that the Company currently assumes is an attempt to push a large amount of that risk onto customers.

Next, Mr. Foley argues that "if the Company consistently spends more on storm restoration O&M than is projected as discussed by CUB-MN Witness Denzler, this will have the impact of raising those projections and the amount recovered from customers in future years under the current approach. If this were to occur, the SRCSM would offer even greater protections than it

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[1030] *Id*. at 165.

[1031] *Id*.

[1032] *Id*.

[1033] Foley Direct, 2 TR 129-32.

[1034] Foley Rebuttal, 2 TR 167-8.

does today since the amount being recovered through rates would be greater than it is today."[1035] The Commission should reject this argument. It boils down to a claim that if storm expense is trending up, then the higher it gets the more probable it is that the SRCSM will produce a credit to customers in the future – even if such a credit is not likely now.

Next, Mr. Foley claims that DTE would not expense as much replacement cost as possible to Storm in order to take advantage of the cost sharing. But other than that bare assertion, there is nothing in record on which to rely for this claim.

In sum, DTE's proposed cost-sharing mechanism has upsides for the Company but none for its customers. Nothing in Mr. Foley's rebuttal changes that conclusion. The Commission should disapprove DTE's proposal.

XIII. STAFF AND INTERVENOR REBUTTAL OF EACH OTHER (RESERVED)

XIV. CONCLUSION

For the reasons stated above, MNSC respectfully requests that the Commission:

A. Reject the Company's projected 2024 investment in the 4.8kV Hardening program and instead reduce spending in 2024 to $6.667 million consistent with the final order in U-21297;

B. Direct the Company to terminate its 4.8kV Hardening program and instead transition the program to DPLD arc wire removal beginning in 2025;

C. Reduce the Company's projected 2025 test year investment in the 4.8kV Hardening program to $43.200 million (a reduction of $81.800 million) to pivot to DPLD arc wire removal only;

[1035] *Id*. at 168.

D. Require the Company to establish and present metrics to budget and monitor DPLD wire removal costs in the next rate case;

E. Reduce the Company's projected test year 2025 investment in the PTMM program to $63.450 million, the level approved in U-21297, a reduction of $57.550 million;

F. Reject the Company's request to include PTMM spending in the IRM in 2026 and 2027;

G. Direct the Company to present an assessment of the reliability difference between PTM circuits and PTMM circuits, to calculate the monetary value of the reliability improvements relative to incremental costs of pole and pole top construction standards;

H. Direct the Company to update its Reliability Model with an analysis of the credible reliability benefits projections for PTMM, Hardening, Conversions, Tree Trimming, and Distribution Automation based on historic data demonstrating outage reductions;

I. Reject the Company's request to include Breaker Replacement Program spending in the IRM in 2026 and 2027;

J. Reject the Company's request to include URD Replacement Program spending in the IRM in 2026 and 2027;

K. Reject the Company's request to include Conversions spending in the IRM in 2026 and 2027;

L. Direct DTE to provide robust, project-specific, risk-informed cost-benefit analysis with a thorough review of alternatives for conversion projects exceeding $10 million before capital investment of $1 million beyond concept and design;

M. Reject the Company's projected 2024 investments in Subtransmission Redesign and Rebuild program, for projects in service in 2024, including $19.274 million for Tie 4105 Phase 3 and $6.062 million for Trunk 3509;

N. Reject the Company's projected test year 2025 investment in Subtransmission Redesign and Rebuild program, for projects in service in 2025, including $2.808 million for Tie 4105 Phase 4;

O. Reject the Company's request to include Subtransmission Redesign and Rebuild spending in the IRM in 2026 and 2027;

P. Direct the Company to provide transparency related to its multi-year Conversion, CODI, and Subtransmission Redesign and Rebuild projects with spending above $10 million, as discussed in this brief;

Q. Reject the Company's request to include Conversions and CODI spending for 2026 and 2027 in its IRM;

R. Require DTE to support the appropriate pace of conversions in its next rate case;

S. Reject the Company's projected test year 2025 increased investment in Distribution Automation and instead maintain 2024 spending levels, a reduction of $101.176 million;

T. Reject the Company's request to include Distribution Automation spending in the IRM in 2026 and 2027;

U. Direct the Company to develop a benefit-cost model to govern Distribution Automation on a circuit-specific basis using actual historical reliability reduction improvements from DTE deployment of Viper reclosers on its circuits;

V. Reject the Company's projected 2024 and test year 2025 investments in Grid Automation Telecommunications, a reduction of $16.900 million in 2024 and $15.0 million in 2025;

W. Reject the Company's planned 2024 and test year 2025 investments n Straegic Undergrounding pilots, a reduction of $15.644 million in 2024 and $16.019 million in 2025;

X. Require the Company to demonstrate that its Distribution Strategic Capital Investments are cost-effective based on deployment of these programs on DTE circuits and with historic outages;

Y. Maintain robust, accurate and verifiable outage data that identifies the cause of distribution outages;

Z. Direct DTE to continue to file annual tree trim reports, as well as PTMM annual reports using the same format, consistent with the order in U-21297;

AA. Direct DTE to cease the capitalization of tree trimming that precedes or is part of capital projects, including without limit Hardening, PTMM, and Distribution Automation investments;

BB. Approve the Company's Charge Forward program and proposed Transportation Electrification Plan, but without endorsing DTE's benefit-cost methodology and without added CIAC, and also require DTE to prioritize NEVI applicants for on-route DCFC charging and public and school transit federal grant recipients.

CC. Reject the Company's request for approval to increase its ROE to 10.5% and instead authorize an ROE of 9.3%;

DD. Order a productivity adjustment to DTE's projected O&M inflation rate, or alternatively, adopt the inflation rate proposed by ABATE or the Attorney General;

EE. Order an independent baseline audit of DTE right-of-ways (ROWs) by no later than the end of 2026, with subsequent independent audits of DTE ROWs to ensure DTE maintains all circuits on the 5-year cycle for ETTP;

FF. Support any transition of circuits to a variable trim cycle with an independent audit and evaluation of the trim planning and the model to evaluate the results and improve the model and outcomes for customers;

GG. Reject the Company's request for recovery of outage credits for a wide variety of causes and limit recoverability to outages caused by the transmission operator or another utility, and on the condition that DTE seek recovery of costs from the responsible party;

HH. Reject the Company's proposal to recover from ratepayers the projected O&M expense saved as a result of the Company's large-scale voluntary buy-out program;

II. Direct DTE to shift from a flat Low-Income Assistance (LIA) credit to a tiered system of credits and adopt additional recommendations discussed above to streamline eligibility documentation and modify arrearage forgiveness credits;

JJ. Reject Staff's recommendation to delay evaluation of proposed improvements to DTE's low-income programs;

KK. Reject the Company's request for a return on its ETTP Surge Regulatory, given the Company's negligent failure to maintain vegetation management on the industry-standard 5-year cycle, or alternatively – if a return is authorized – it should be maintained at the short-term debt rate;

LL. Direct DTE to file an analysis in its next rate case of the seasonality of distribution cost causation, and to evaluate potential residential sub-classes for multi-family homes and electric heating;

MM. Direct DTE to maintain accurate and up-to-date CIAC rates based on construction costs with regular updates to its CIAC standards; and

NN. Reject the Company's request to extend the IRM to 2026 and 2027 and increase IRM spending in 2025, 2026, and 2027.

Respectfully Submitted,

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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 **Initial Brief of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan** was served on the following:

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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

Confidential Proof of Service

On the date below, an electronic copy of **Confidential Version of the Initial Brief of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan** was served on the following:

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