July 26, 2022

Ms. Lisa Felice ***Via E-Filing***
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-20836

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Initial Brief of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (Public Version); and

Proof of Service.

Please note that the Confidential Version of the Initial Brief of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan will be served via email only to those with a Nondisclosure Certificate on file in this case.

Sincerely,

Digitally signed by Tracy Jane Andrews
DN: cn=Tracy Jane Andrews, email=tjandrews@envlaw.com, c=US
Date: 2022.07.26 16:23:20 -04'00'

Tracy Jane Andrews
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xc: Parties to Case No. U-20836

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	U-20836

PUBLIC VERSION

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

July 26, 2022

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I. INTRODUCTION

In this case, DTE Electric Company (DTE) seeks a rate increase of $388 million for a projected test year of November 1, 2022, through October 31, 2023.[1] This is a proposed 7.5% increase in total. The revenue increase impacts residential customers more substantially than secondary and primary customers: [2]

Total Residential	Total Secondary	Total Primary
8.8%	7.7%	4.1%

For residential customer bills, this increase amounts to about a monthly $9 to $11 increase for customers whose monthly consumption is 600 to 700 kWh.[3]

The drivers of increasing rate base are principally the Blue Water Energy Center, maintenance investments in other Production Plant, and considerable proposed capital expenditures for the distribution system.[4] DTE residential customers already suffer poor distribution system reliability (outages) and high rates.[5] Increasing distribution investments are allocated relatively higher to the residential class. DTE's policy for contributions from new customers and new load (contribution in aid of construction, or CIAC policy) also disproportionately burdens residential ratepayers relative to other classes. These and additional issues discussed in this brief raise statutory, practical, legal, and policy concerns that warrant careful consideration before the Commission approves any portion DTE's requested rate increase, particularly given the compound impact on residential customers.

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[1] DTE Electric, Jan. 21, 2022, Application, p. 2; Direct Testimony of Adella Crozier, 7 TR 2348.

[2] DTE Application, Attachment 2.

[3] *Id.*, Attachment 3.

[4] Crozier Direct, 7 TR 2349; Ex A-12, Sch. B1; Jester Direct, 8 TR 3776.

[5] Jester Direct, 8 TR 3779-92, 3796.

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:

(1) Power Generation: The Commission should disallow proposed capital investments in the Belle River plant, including capital investments that may be avoided should the plant retire in 2026 and costs associated with the exploration of converting the plant from coal to gas. In addition, the Commission should disallow avoidable or premature environmental compliance costs while the EPA revision to the ELG rule is pending.

(2) Resource Adequacy in Zone 7: The Commission should not give any weight to DTE's projections that MISO Zone 7 will be short on capacity if Belle River retires early, as those projections are based on selective and inaccurate assumptions.

(3) Distribution System Spending and Programs: The Commission should disallow recovery of $93.675 million in the bridge and test periods in the 4.8kV Hardening program, $80.539 million in the bridge and test periods in the Pole and Pole Top Maintenance and Modernization (Pole/PTMM) program, and $571.512 million in the bridge and test periods for the Strategic Undergrounding Pilots. The Commission should also recognize extensive proposed overcapitalization in the Company's distribution capital programs, particularly the 4.8kV Hardening and Pole/PTMM programs. DTE should be directed to explore the reliability benefits of new machine-learning based instantaneous distribution system monitoring technologies.

(4) Cost of Equity: The Commission should reject DTE's requested increase in awarded return on equity and instead should substantially reduce ROE.

(5) Tree Trimming: The Commission should direct DTE to continue its tree trimming program and consider efficiencies achievable through a variable cycle approach.

(6) Rate D1.11 TOU implementation: The Commission should support the Company's proposal to transition residential customers on an opt-out basis to TOU rates for capacity and non-capacity power supply, but should direct DTE in its next rate case to include TOU rates for distribution costs.

(7) Rate D1.12 Stable Bill Service Level: The Commission should reject the Company's proposed new Rate D1.12 because it is unreasonable, inequitable, and contrary to Commission policy.

(8) Contribution in Aid of Construction (CIAC) Reform: With growing investments to connect new customers and an obvious appetite by DTE to maintain the status quo (established *circa* 1976), the Commission should continue the Staff-led CIAC reform discussion to improve the calculation and allocation of ratepayer-funded contributions for new customer connections.

(9) Distributed Generation: The Commission should deny DTE's requests to require all DG customers to take service on Rate Schedule D1.12 – the so-called Stable Bill Rate – and to reduce the outflow credits to locational marginal price. Instead, the Commission should require that Rider 18 outflow bill credits be equal to the production cost at the time of outflow, inclusive of transmission costs, and further direct DTE to provide an analysis in its next case of the cost of service for behind-the-meter DG customers.

(10) Hydrogen Pilot: The Commission should not approve for inclusion in rate base $19 million in capital expenditures for a hydrogen electrolyzer at the Blue Water Energy Center plant. The hydrogen project is an inordinately expensive way to produce a small amount of energy and DTE has not demonstrated any plan to fulfill its representations that the project will be green.

(11) Distribution Project Capitalization: The Commission should recognize and address the extensive overcapitalization of inspections and tree trimming in the Company's distribution capital programs, particularly the 4.8kV Hardening and Pole/PTMM programs.

(12) Charging Forward and New EV Programs: MSNC supports the Company's proposals to expand the Charging Forward program, with modifications to better align the programs with the Commission's high-level principles for EV-related utility program. MNSC recommends modifications that would future-proof charging sites, integrate time-based rates for residential charging, make rebates available at the vehicle point of sale, and share information related to siting charging hubs. MNSC further recommends that DTE show how it will transition the program to permanent in its next rate case.

(13) Cost Allocation: The Commission should reassign the fixed cost of the MERC facility from production cost to fuel cost, and do the same with the labor expense component of fuel handling O&M.

(14) Distributed Generation (DG) Program: The Commission should deny DTE's requests to require all DG customers to take service on Rate Schedule D1.12 – the so-called Stable Bill Rate – and to reduce the outflow credits to locational marginal price. Instead, the Commission should require that Rider 18 outflow bill credits be equal to the production cost at the time of outflow, inclusive of transmission costs, and further direct DTE to provide an analysis in its next case of the cost of service for behind-the-meter DG customers.

(15) Heat Pump Pilot: The Commission should direct DTE, in collaboration with Staff and stakeholders, to develop a pilot program to electrify propose, oil and kerosene heated homes.

(16) Value of Reliability Study: The Commission should also ensure DTE undertakes a meaningful value of reliability study to support its proposed distribution investments, supported by a survey of DTE customers who have experienced outages.

II. RATE CASE CONTEXT AND STANDARDS

The Commission should consider the Company's rate relief request within the context of current and historic conditions in its service territory.[6] In setting just and reasonable rates, the Commission must consider how the requested rate increases may impact DTE Electric's customers.[7] "The ratemaking process involves a balancing of investor and consumer interests."[8] In particular, the Commission should be particularly wary of discretionary spending that is driving the requested rate increase because it will exacerbate the heavy burden on residential customers.

As noted above, the Company's proposals will impose a nearly 9% rate increase on residential customers, driving average bills up by about $10 per month. Bills are not the only relevant measure of customer impact; average annual bills fluctuate year over year due to weather, while rates steadily increase. This table from a Company discovery response illustrates the point

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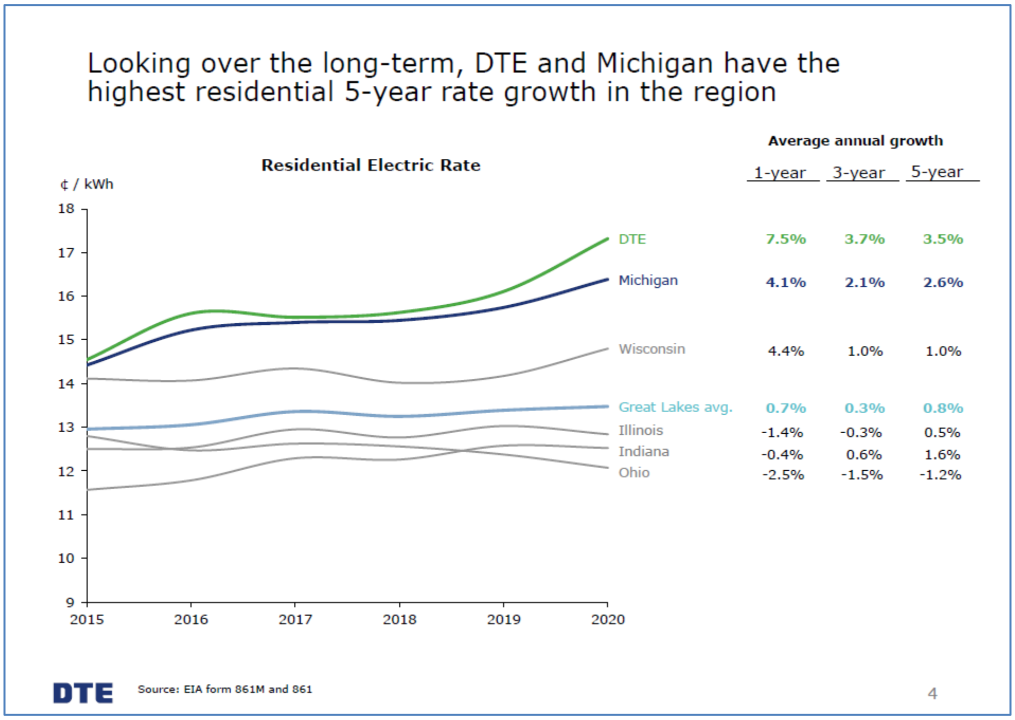
[6] See *Detroit v Public Serv Comm*, 308 Mich 706, 716-18; 14 NW2d 784 (1944).

[7] *Id.*; see also *Federal Power Comm v Hope Natural Gas Co*, 320 US 591, 602-603 (1944) (in setting just and reasonable rates, it is "the impact of the rate order which counts").

[8] *ABATE v Public Service Comm*, 208 Mich App 248, 266; 527 NW2d 533 (1994).

starkly:[9]



Rate changes more accurately reflect regulatory decisions than do average customer bills because rates do not change with the weather. DTE customers across all classes already pay rates that are substantially higher than national and Midwest averages, with average electric bills already having increased 15% from 2019.[10] Even before this proposed rate increase, DTE and Michigan average residential rates were already 31% above the US average and 28% above the regional average.[11] DTE now asks for another rate increase on top of these already-excessive rates, which will even further burden the residential class.

Another relevant context for the Commission to consider this rate increase request is from the perspective of the Company's overall performance. Referencing a respected paper, MNSC witness Douglas Jester noted the necessity of regulation to define standards for performance and

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[9] Ex MEC-4, p. 5.

[10] *Id.* at p. 7.

[11] *Id*, p. 10.

assign positive and consequences for performance in order to align private behavior with the public interest.[12] Mr. Jester assessed DTE's performance using standard metrics of reliability, affordability, and environmental emission.[13] Across these metrics, the Company's performance relative to other utilities is somewhat worse than the national median in all respects.[14] DTE's reliability performance is poor and deteriorating, its rates are worse than both average and median rates nationally, and its emissions are also worse than average, particularly for sulfur dioxide.

Another consideration in setting just and reasonable rates in this case is the relative burden of the rate increase among the classes. The primary driver of the rate increase requested in this case is the significant increase in distribution system investments (Delivery Revenue), which are heavily allocated to residential customers. The Company proposes to spend ***$1.4 billion*** dollars on its distribution system in the projected test year ending October 31, 2023, a substantial ***$519 million*** increase over 2020 spending[15] Distribution spending, particularly discretionary (or "Strategic") spending, thus warrant particular scrutiny.

In acting on DTE's proposed rate increase request, the Commission must consider the totality of the circumstances and impacts. In addition to the lack of support or justification for multiple proposed expenditures, the Commission should be particularly skeptical of discretionary reliability spending that increases the burden on residential customers. The Commission should look for economically efficient and cost-effective ways to improve reliability while limiting

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[12] Jester Direct, 8 TR 3776 (citing Hempling, S. Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction. American Bar Association Section of Environment, Energy, and Resources. 2013.)

[13] Jester Direct, 8 TR 3776-97.

[14] *Id.* at 3796.

[15] Ex A-12, Sch. B-5.4.

increasing residential rates. MNSC witnesses recommend ways to do so in this case.

III. RATE BASE

A. Steam, Hydraulic & Other Power

1. The Commission Should Disallow Recovery of $15.248 Million in Avoidable or Premature Costs Related to the Belle River Plant.[16]

Under Michigan law, a utility bears the burden of demonstrating that a requested rate increase is just and reasonable.[17] As economically marginally generating units in recent years have faced increased costs related to age and environmental standards, and the declining costs and increasing availability of renewable and demand-side resources, the Commission has been increasingly faced with the question of what level of further spending on these units utilities should be allowed to recover from their customers. In these situations, the Commission has made clear that a careful evaluation of the utility's proposed spending is necessary to ensure that the costs are just and reasonable for customers to incur.[18] Pursuant to this standard, the Commission has not hesitated to disallow cost recovery for capital spending on generating units where such spending

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[16] MNSC witness Comings also recommended disallowance of cost recovery for a handful of capital projects at the Monroe plant given the anticipated evaluation in DTE's upcoming IRP of earlier retirement dates for one or more of the units at that plant and record evidence suggesting that such projects may not be economic under early retirement scenarios. Comings Direct, 8 TR 4069-79. In light of further record development through rebuttal testimony and discovery, MNSC has decided to no longer pursue the recommended Monroe disallowances in this proceeding though, of course, reserve all rights to address issues regarding Monroe costs and retirement dates in future proceedings.

[17] MCL 460.6a(1); *see also* MCL 460.6, 460.54, and 460.551 *et seq.*

[18] See, e.g., Case No. U-16794, June 7, 2012, Order, p. 13 ("if the utility realistically expects inclusion of the total projected costs, it must supply the Commission with enough evidence to support a finding that the costs are just and reasonable – in the absence of thorough, detailed, and meaningful evidence, the Commission's hands are tied.").

would be avoidable under economic retirement dates and/or the utility has otherwise not demonstrated that it is just and reasonable.[19]

MNSC urges such disallowance with regards to $15.248 million in bridge year and test year capital spending regarding the Belle River plant, the retirement date for which will be a focus of DTE's upcoming Integrated Resource Plan ("IRP") filing that is expected in October 2022. $12.775 million of the proposed disallowance is for five capital projects that the Company acknowledges would be avoidable in a 2026 Belle River retirement scenario. Such disallowance is necessary to protect customers because the available evidence shows that 2026 is the most economic retirement date under all capacity prices except the unreasonable assumption that the highest possible capacity prices would be maintained through at least 2028. The remaining $2.473 million disallowance is for an engineering study of converting Belle River to operate on gas rather than coal. Cost recovery for that study is premature given that the Company has not made any decision to proceed with such gas conversion and already has sufficient analysis to evaluate the potential conversion in the upcoming IRP.

a. Prior Commission orders regarding the economics of, and potential retirement dates for, the Belle River plant.

The Commission has addressed the economics of, and potential retirement dates for, the Belle River in two recent proceedings. First, in its 2019 IRP filing, No. U-20471, DTE proposed retiring the two Belle River units in 2029 and 2030, respectively. In that filing, the Company evaluated, at the request of Sierra Club, an earlier 2025/26 retirement date but contended that it would be more costly than continued operation of Belle River until 2029/30. MNS identified numerous flaws in DTE's analysis, including that it failed to account for certain environmental

[19] See, e.g., Case No. U-18014, January 31, 2017, Order, p. 17; Case No. U-18255, April 18, 2018, Order, p. 8; Case No. U-20162, May 2, 2019, Order, pp. 11-12; Case No. U-20561, May 8, 2020, Order, p. 25.

capital costs that would need to be incurred if Belle River operated until 2029/30 but not if the plant retired in 2025/26. The Commission agreed with MNS's critique (which the ALJ had also agreed with), finding that the Company's retirement analysis was "inadequate and fail[ed] to demonstrate that the 2029/2030 retirement scenario is reasonable and prudent."[20] The Commission ordered the Company to provide a more complete Belle River retirement analysis in its upcoming IRP, while also holding that:

> In the meantime, the Commission will continue to carefully scrutinize near-term capital expense and O&M costs as part of the economic analysis necessary to making these investment and cost recovery decisions in rate cases. . . . As the Commission has not found the proposed 2029/2030 retirement date to be reasonable and prudent, there is explicitly no presumption of reasonableness and prudence involving additional expenditures needed to keep the plant running.[21]

A few months later, the Commission issued its ruling in DTE's 2019 rate case, No. U-20561. In that proceeding, MNS identified another flaw in the Belle River retirement analysis that the Company had presented in its 2019 IRP; namely, that the analysis failed to fully account for the fixed costs associated with keeping Belle River open until 2029/30 and how those costs would ramp down in the years leading up to retirement in either 2025/26 or 2029/30. MNS urged the Commission to require DTE to submit in its next rate case (i.e. the present proceeding) an updated analysis of the most economic retirement date for Belle River, and to ensure that cost recovery reflected in such rate case reflected the ramp down in fixed costs for such retirement date. The Commission agreed with MNS's position, and required DTE to file a "revised NPVRR analysis for this plant using alternative retirement dates in its next rate case."[22] In doing so, the Commission

[20] Case No. U-20471, Feb. 20, 2020, Order, p. 37.

[21] *Id.* at 37-38.

[22] Case No. U-20561, May 8, 2020, Order at 81-82.

further noted that "such an analysis will assist in its reasonableness and prudence determination as to the company's requested expenditures for this plant in the next rate case."[23]

b. DTE's NPVRR analysis in the present proceeding[24]

With its application, the Company presented a net present value revenue requirement ("NPVRR") analysis of three potential Belle River retirement dates – 2026, 2028, and 2030 – compared to retiring the plant in 2023. DTE evaluated each retirement date under one of four possible MISO capacity auction prices – 0%, 10%, 50%, and 100% of the cost of new entry ("CONE").[25] As summarized by MNSC witness Tyler Comings, the Company's NPVRR analysis found that the most economic retirement year for Belle River would be 2023 at 0% and 10% of CONE, and 2026 at 50% of CONE.[26] Only at the highest possible capacity price of 100% of CONE did the analysis find 2028 to be the most economic retirement year.[27] As witness Comings explained, such results are driven in large part by the fact that DTE's own projections show a $70 million savings in capital costs if Belle River is retired in 2026 rather than 2028.[28]

In discovery, DTE also produced the results of what it refers to as "practice" analyses for its upcoming IRP filing, in which the Company modeled alternative retirement dates for both Belle

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[23] *Id*.

[24] MNSC believes the following portions of the record are relevant to the Belle River NPVRR analysis:

- Burgdorf Direct, 4 TR 135-139;
- Burgdorf Rebuttal, 4 TR 148-49;
- Ex. A-12, Sch. B6.1 to B6.3;
- Comings Direct, 8 TR 4053-4059; and
- Exhs. MEC-59, 60, and 63.

[25] Comings Direct, 8 TR 4055. CONE is based on the annual cost of building and operating a new gas-fired combustion turbine.

[26] *Id.* at 4056, citing Ex. A-12, Schedule B6.1 to B6.3.

[27] *Id.*

[28] *Id.* at 4057-58.

River and Monroe.[29] [[[redacted]]]

c. The Commission should disallow cost recovery for Belle River capital costs that DTE acknowledges would be avoidable in a 2026 retirement.[31]

Despite the NPVRR results showing that it would be most economic to retire Belle River in 2026 (or earlier) under all but the highest possible capacity price, DTE assumes in the present proceeding that Belle River will continue operating on coal until the end of 2028. In particular, of the $45.69 million in projected test year capital expenditures at Belle River, approximately $12.775 million is for capital projects that the Company acknowledges would be avoidable in a 2026 retirement scenario.[32] In response to a discovery request, the Company identified five such avoidable projects at Belle River – project IDs 17532, 17531, 17996, 15301, and 15595.[33]

As witness Comings explains, cost recovery for those five avoidable projects should be denied given that DTE's own NPVRR results support the conclusion that under reasonable capacity price assumptions a 2026 retirement is the most economic option for the Belle River plant. At a minimum, the available economic analyses demonstrate that a 2026 Belle River retirement is

[29] Comings Direct, 8 TR 4070-72, citing Exhibit MEC-63C (NDA_U-20836 MNSCDE-1.6a Practice Belle River and Monroe Analyses).

[30] *Id.*

[31] MNSC believes the following portions of the record are relevant to the Belle River avoidable cost disallowance issue:

- Comings Direct, 8 TR 4067-68;
- Exhs. MEC-60 and 73; and
- Morren Rebuttal, 5 TR 750-51.

[32] Comings Direct, 8 TR 4067-68.

[33] *Id.* at 4067; Ex. MEC-73.

a potential outcome of the upcoming IRP proceeding. Granting cost recovery for such avoidable projects now, however, would deprive customers of the savings from avoiding those costs in the event of a 2026 retirement, and would skew the upcoming IRP analysis towards a 2028 retirement by turning those 2026 avoidable costs into stranded ones.[34] As such, cost recovery for the $12.775 million in avoidable capital projects at Belle River should be denied in this proceeding, as this Commission has found in other similar situations.[35]

In rebuttal, DTE witness Morren contends that the 2026 avoidable Belle River capital projects should not be disallowed because "the Company has not made a decision to retire the plant in 2026."[36] DTE contends that the NPVRR results are not the only factor relevant to a retirement decision. Instead, Mr. Morren opines that a number of other factors, such as resource adequacy and grid reliability, need to and will be considered in the upcoming IRP in order to determine the most reasonable retirement date for Belle River.[37] But the Commission has already found that the absence of a definitive retirement date is not a bar to the disallowance of avoidable capital costs.[38] This is especially so in situations, such as here, where the IRP proceeding in which a comprehensive retirement analysis will be carried out is expected to start soon.[39] Such an approach

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[34] Comings Direct, 8 TR 4067; Case No. U-20697, December 17, 2020, Order at 75, 77 (in disallowing cost recovery of $1.732 million in avoidable capital costs, Commission adopted the ALJ's findings, which included that "promoting such expenditures on the eve of a comprehensive retirement analysis may unnecessarily add to the burden on ratepayers".).

[35] Case No. U-20697, December 17, 2020, Order at 77 (disallowing costs avoidable in a 2024 retirement scenario where evidence showed that 2024 was a potential retirement year in an upcoming IRP proceeding); Case No. U-18322, March 29, 2018, Order at 24 (deferring recovery of $1.6 million in avoidable capital costs at Karn units for which retirement dates were to be evaluated in upcoming docket).

[36] Morren Rebuttal, 5 TR 750.

[37] Morren Rebuttal, 5 TR 751.

[38] See, e.g., Case No. U-18322, March 29, 2018, Order at 22, 23 (denying recovery of $1.6 million in avoidable costs despite utility's protestation that no retirement decision had been made).

[39] Case No. U-20697, Dec. 17, 2020, Order at 77.

is reasonable because while customers would lose out on the opportunity to receive avoided costs savings if recovery of those costs were authorized now, the Company can always seek recovery of such costs in the future if they end up being incurred and are demonstrated to be reasonable and prudent.[40] As such, disallowance of the 2026 avoidable costs is appropriate and necessary to protect customers while the future of the Belle River plant gets worked out.

d. <u>The Company's claimed resource adequacy concerns do not justify charging customers for the 2026 avoidable capital costs at Belle River.</u>

In particular, Mr. Burgdorf claims in rebuttal that there is a "very likely chance that Zone 7 capacity will be priced at CONE without Belle River's capacity" and that, therefore, the NPVRR scenario involving capacity prices at 100% of CONE is the most reasonable one to use.[41] In support, witness Burgdorf presents in his rebuttal testimony an updated analysis of planning year 2025/26 resource adequacy in Zone 7 in which he projects a 1,210 MW capacity shortfall in Zone 7 in the event that Belle River were to retire by the end of 2026.[42]

2. DTE makes inaccurate projections concerning resource adequacy in an attempt to justify capital spending to continue uneconomic operation of the Belle River plant.[43]

Witness Morren, relying heavily on the testimony of Company witness Shawn Burgdorf, also critiques witness Comings' testimony on the grounds that resource adequacy concerns in

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[40] *Id.*

[41] Burgdorf Rebuttal, 4 TR 148-49.

[42] Burgdorf Rebuttal, 4 TR 146.

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

- Direct testimony of Shawn Burdorf, 4 TR 128-35;
- Direct testimony of Tyler Comings, 8 TR 4059-66;
- Rebuttal testimony of Shawn Burdorf, 4 TR 141-49;
- Cross examination, redirect, and recross of Shawn Burgdorf, 4 TR 153-214;
- Exhibits A-33, Schedules X1-X3 and Exhibit A-50; and
- Exhibits MEC-54, 56, 57, 62, 65, 67, 72, and 78-89.

MISO Zone 7 justify continuing to operate Belle River through the end of 2028 rather than retiring the plant in 2026.[44] In direct testimony, DTE witness Burgdorf projected that MISO Zone 7 would be short on capacity in Planning Year 2025/2026 if the Belle River plant retired that year. Mr. Burgdorf offered this projection for two purposes: (1) to support the highest capacity price scenario used in DTE's economic analysis, which was 100% of CONE every year; and (2) to argue that regardless of the economic analysis, Belle River should not be retired in PY 25/26 because of reliability concerns.

As to capacity prices, as witness Comings details, experience with capacity prices in MISO shows that there is little reason to believe that capacity prices in Zone 7 would stay at 100% of CONE for years to come.[45] While Zone 7 capacity prices have been quite volatile over the past nine auctions (ranging from 1% to 100% of CONE), the average price has been 27% of CONE over that time frame.[46] In fact, the only capacity price forecast that the Company produced in this proceeding has a price jump in planning year 2022, but then projects that prices will fall to and remain at quite low levels for planning years 2023 through at least 2026.[47] As such, while there have been a couple of recent spikes in MISO Zone 7 capacity prices, there is little reason to believe that past MISO capacity market behavior will change so dramatically as to have prices stay at 100% of CONE through 2028.

As to DTE's proffered reliability concerns, in his direct testimony, MNSC witness Tyler Comings showed that Mr. Burgdorf's projection was inaccurate because he relied on incorrect and out-of-date information concerning Consumers Energy's future capacity position. In rebuttal, Mr.

[44] Morren Rebuttal, 5 TR 751.

[45] Comings Direct, 8 TR 4060-61.

[46] *Id.*

[47] Ex. MEC-65.

Burgdorf responded by offering a new projection based on different methodology and assumptions from his direct testimony projection. The new projection once again predicted Zone 7 would be short in PY 25/26 if Belle River retired. The Commission should not rely on this new projection because Mr. Burgdorf selectively used only those assumptions that would maximize the shortfall, and ignored a good deal of other information that weighed in the opposite direction. Illustrating this point requires some detailed explanation.

In Table 5 of his testimony, Witness Burgdorf projects the future capacity position of MISO Zone 7 relative to the Local Clearing Requirement, or LCR, for several years.[48] The key year is 2025/26, where he projects an anticipated LCR position without Belle River that ranges from a deficit of 748 Zonal Resource Credits to a surplus of 940 ZRCs, depending on the Capacity Import Limit, or CIL.[49] He made this estimate via the following steps, which correspond to the line numbers in the table:

1. He assumed peak demand in Zone 7 of 20,399 MW for 2025/26. He calculated this number by taking the MISO peak demand forecast for the Zone from the 2020 Loss of Load Expectation (LOLE) report and switching out the peak demand forecast DTE submitted for that report with a higher forecast that DTE used for this rate case.[50]
2. He assumed a Per-Unit Local Reliability Requirement (LRR) of 119.4%. He obtained this number from the MISO 2022/23 LOLE Report, which projected it as the value for 2022/23. Mr. Burgdorf assumed that MISO's projected per-unit LRR for 2022/23 would remain the same through 2025/26.[51]

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[48] Burgdorf Direct, 4 TR 134.

[49] *Id*.

[50] Ex MEC-62, workpaper titled "MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast," p. 3, sheet titled "Historical zone 7 peak demand;" Burgdorf Cross, 4 TR 169.

[51] Burgdorf Direct, 4 TR 132; Burgdorf Cross, 4 TR 191.

3. He estimated the LRR for Zone 7 by multiplying his assumed peak demand of 20,399 MW for 2025/26 by his assumed LRR of 119.4%, which came out to 24,356 MW.[52]
4. He assumed a range of future CILs for 2025/26 of 3,200 to 4,888 MW, based on historic numbers for 2018 to 2022.[53]
5. He multiplied the LRR by the range of CILs to get an LCR of 19,468 to 21,156 MW for 2025/26.
6. He assumed that Zone 7 would have 21,623 of resources in 2025/26. He calculated this number by starting with the estimate in the MPSC Staff report from the 2020 capacity demonstration docket, U-20886.[54] Then he added DTE resources newly confirmed since then totaling 850 MW; subtracted 923 MW for his interpretation of the change in Consumers Energy's capacity position as a result of its IRP; and subtracted another 247 MW to represent an assumed delay in development of renewables.[55] The subtraction of 247 MW was not due to any project-specific information, but rather was meant to reflect a general risk associated with solar development.[56]
7. He then stated a 2025/26 Zone 7 capacity position relative to the LCR as the difference between the Zone 7 resources and the LCR he projected for that year.
8. Finally, he reported the anticipated Zone 7 LCR position in 2025/26 without Belle River as the difference between the Zone 7 resources and LCR he projected for that year, minus the 1,215 MW capacity of Belle River. This calculation produced the range of (748) to 940 ZRCs.

[52] Burgdorf Cross, 4 TR 190.

[53] Burgdorf Direct, 4 TR 133; Burgdorf Cross, 4 TR 197.

[54] Ex MEC-62, p. 5, sheet titled "Zone 7 CapDem Resource Forecast."

[55] Burgdorf Cross, 4 TR 186; Ex MEC-62, p. 5, sheet titled "Zone 7 CapDem Resource Forecast."

[56] Burgdorf Direct, 4 TR 132; Burgdorf Cross, 4 TR 186.

MNSC witness Tyler Comings testified that the premise of Mr. Burgdorf's projections was misguided and that his assumptions regarding Zone 7 resources were also inaccurate. With respect to the premise, Mr. Comings explained that Mr. Burgdorf's projections assume that DTE would retire Belle River without replacing any of its capacity.[57] That assumption is not realistic.[58] As just one example, DTE is presently studying conversion of Belle River to gas.[59] According to Company witness Justin Morren, such a conversion – if approved – would maintain the same or nearly the same capacity at Belle River.[60] Also according to Mr. Morren, a conversion would take only 18 months to two years;[61] and so DTE believes it is feasible by 2025/26. Cleaner options such as wind, solar, storage, and firm power purchases also exist. The point is that DTE would not retire Belle River "in a vacuum," and so Mr. Burgdorf's assumption that such a retirement would reduce Zone 7 capacity by 1,215 MW is invalid.[62]

With respect to the accuracy of the projected Zone 7 resources, MNSC witness Comings explained that Mr. Burgdorf estimated a reduction of 923 ZRCs from Consumers Energy's capacity position as a result of his IRP. Without that reduction, Mr. Burgdorf would have projected a surplus of capacity in Zone 7 for 2025/26, even with Belle River retiring and no replacement capacity.[63] However, Mr. Burgdorf made a mistake interpreting the Consumers IRP, and several developments have occurred in that case since DTE filed this case that positively impact Consumers' future capacity position.

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[57] Comings Direct, 8 TR 4066.

[58] *Id*.

[59] Morren Direct, 5 TR 645, 651.

[60] *Id*. at 651; Morren Cross, 5 TR 767-68.

[61] Morren Cross, 5 TR 769.

[62] Comings Direct, 8 TR 4066.

[63] *Id*. at 4063.

The mistake was using the wrong page of the relevant exhibit from Consumers' IRP. To estimate Consumers Energy's resource changes, Mr. Burgdorf used page 5 of Exhibit A-14 in Consumers' IRP case (U-21090) for the Company's Proposed Course of Action, or PCA.[64] However, Consumers witness Sara Walz testified that page 9 of that exhibit presented the PCA.[65] The mistake underestimated Consumers' capacity position by 74 ZRCs.[66] Mr. Burgdorf did not respond to this point in rebuttal.

In addition, there were three changes to Consumers' IRP that positively impacted its capacity position between the filing of Case No. U-21090 and its settlement. Those changes were:

- Consumers will continue operating Karn units 3-4 beyond 2023, adding 784 ZRCs in planning year 2025/26 compared to the IRP filing.
- A new battery storage investment will add 14 ZRCs by 2025/26, with more coming later.
- A competitive solicitation for PPAs will provide capacity credit in Zone 7 starting in the 2025 planning year. The solicitation will have two tranches: one for 500 ZRCs of dispatchable generation and one for 200 ZRCs of clean capacity resources. Mr. Comings testified that to be conservative, he assumed that the 500 ZRC tranche would come from existing generation – and therefore not increase Zone 7 capacity – but the second tranche would come from new resources that would increase capacity in Zone 7.[67]

Mr. Comings concluded that because Consumers' plans have changed substantially, Mr. Burgdorf's estimate of Zone 7 resources in 2025/26 was outdated and inaccurate.[68]

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[64] Comings Direct, 8 TR 4064; Ex MEC-62, p. 7.

[65] *Id.*; Ex MEC-72, p. 3.

[66] Comings Direct, 8 TR 4065.

[67] Comings Direct, 8 TR 4065-66.

[68] *Id*. at 4066.

In his rebuttal, Mr. Burgdorf did not contest the accuracy of these increases in Consumers' capacity position. Instead, he produced a new forecast of resource adequacy that still showed a deficit in Zone 7 if Belle River retires in 2025/26 with no replacement of any of its capacity.[69] In fact, Mr. Burgdorf's new projection was much worse than the one he submitted five months earlier: (1,524) MW to a 545 MW.[70] To obtain this result, he had to change several of the methods and assumptions he used to produce the earlier forecast. These changes were selective in the sense that Mr. Burgdorf only changed assumptions that *reduced* Zone 7's capacity position relative to the LCR, and did not incorporate any new information that would *increase* Zone 7's capacity position relative to the LCR. Because the new forecast changed methods and assumptions selectively to reach a pre-determined result, it should be given no weight. The details follow.

<u>Line 1 – Peak demand</u>. In the new forecast, Mr. Burgdorf replaced DTE's forecast of bundled peak demand from this rate case with a new, higher forecast of bundled peak demand from its upcoming IRP case.[71] A higher peak demand forecast results in a higher LCR, which makes the Zone 7 capacity position relative to LCR worse. DTE created the new IRP peak demand forecast on January 31, 2022, but did not incorporate it into Mr. Burgdorf's revised direct testimony that the Company filed in March of this year.[72] DTE also stated that the IRP peak demand forecast could not be produced in discovery.[73] Use of the new IRP forecast therefore

[69] Burgdorf Rebuttal, 4 TR 146, Table 7.

[70] *Id*. and Ex MEC-79, workpaper titled "WP Zone 7 Resource Forecast – Updated_V2," p. 1. As of this writing, the revised version of Mr. Burgdorf's Rebuttal Table 7 appears in the electronic version of the transcript, but the revisions do not appear if the testimony is printed out. The original version of the rebuttal table had different numbers for many of the values. The original numbers for capacity position relative to LCR were (1,815) MW to a 258 MW.

[71] Burgdorf Cross, 4 TR 181-82; Ex MEC-79, workpaper titled "WP Zone 7 Resource Forecast – Updated_V2," p. 3.

[72] Burgdorf Cross, 4 TR 182.

[73] *Id*.

contravenes MRE 703 and Commission precedent, which require that forecasts relied on by an expert witness be in evidence.[74]

Additionally, the new IRP peak demand forecast Mr. Burgdorf used was the forecasted DTE system peak.[75] DTE's new IRP peak demand forecast also projected a DTE peak coincident with the MISO system peak.[76] The DTE peak coincident to the MISO system peak is lower than DTE's non-coincident peak.[77] Therefore, using DTE's non-coincident peak made the LCR higher than using the peak coincident to MISO, and thus made the Zone 7 capacity position relative to LCR worse. Mr. Burgdorf stated that MISO uses the non-coincident peaks of the load serving entities within MISO to calculate the LRR.[78] However, two MISO documents admitted into evidence state otherwise. The MISO Resource Adequacy Business Practice Manual states: "The LRR study utilizes the Year 2 zonal coincident peak demand supplied by LSEs in the prior Planning Year PRA cycle."[79] And the LOLE Report for 2022/23 provides the following equation in the section titled "LRZ LOLE Analysis and Local Reliability Requirement Calculation":

LRR UCAP = (Unforced Capacity + UCAP Adjustment to meet a LOLE of 0.1 days per year – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand.[80]

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[74] MRE 703: "The facts or data in the particular case upon which an expert bases an opinion or inference shall be in evidence…" See also, Case No. U-16582, December 20, 2011, Order, p 15 ("Without the forecast information underlying the proposed transfer price schedule, the other parties were denied the opportunity to test the company's evidence, a clear violation of their right to due process.") and Case No. U-17302, Dec. 19, 2013, Order, p 3 ("The Commission agrees with MEC that the pertinent testimony by Mr. Conlen should be stricken because the company failed to provide the reports on which the testimony was based.").

[75] Ex MEC-80C, discovery response MNSCDE-8.26 Supplemental, DTE Electric Capacity Demonstration Ex 1-5 from U-21099, p. 3, "Ex. 1 Demand," line 3, column i; Burgdorf Cross, 4 TR 175.

[76] Ex MEC-80C, p. 3, line 6, column i; Burgdorf Cross, 4 TR 175.

[77] Burgdorf Cross, 4 TR 175; Ex. MEC-80C, p. 3.

[78] Burgdorf Cross, 4 TR 174.

[79] Ex MEC-81, MISO Resource Adequacy Business Practice Manual, p. 101.

[80] Ex MEC-86, LOLE Study Report for 2022/23, report p. 23, exhibit p. 24.

Thus, both the MISO BPM on resource adequacy and the LOLE report indicate that *coincident* peak demand should be used to calculate LRR. These authorities suggest that when Mr. Burgdorf swapped out DTE's original forecast with a higher forecast, he should have used the Company's lower coincident peak rather than its higher non-coincident peak. Doing so would reduce the LRR, which would in turn reduce the LCR and improve the Zone 7 capacity position relative to LCR.

<u>Line 2 – Per-Unit LRR</u>. In his new forecast, Mr. Burgdorf also switched from assuming that per-unit LRR in 2025/26 would be equivalent to the projected 2022/23 value from MISO's 2022/23 LOLE report, to assuming a range of per-unit LRR. The range was from the MISO 2022/23 value of 119.4% to 121.2%.[81] The latter value is the worst per-unit LRR value seen in recent years.[82] So Mr. Burgdorf did not use the range of recent historic per-unit LRR values, which was 115.3% to 121.2%; he only used the worst value.[83] Changing from a single LRR value to a range between a MISO projection and the worst historic value had two effects. First, it increased the range of capacity position relative to LCR results, because Mr. Burgdorf was now calculating based on a range of CILs and a range of per-unit LRRs rather than just the range of CILs in the original projection.[84] Second, it worsened the results, because a higher per-unit LRR will produce a higher LCR.[85]

Even more concerning, Mr. Burgdorf did <u>not</u> use MISO's own forecast of per-unit LRR for 2025/26. That number is 113.6% – much lower than either of the numbers in the range Mr.

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[81] Burgdorf Rebuttal, 4 TR 147.

[82] Burgdorf Rebuttal, 4 TR 147; Burgdorf Cross, 4 TR 193-94.

[83] Burgdorf Direct, 4 TR 131 and Burgdorf Cross, 4 TR 192 (historic range); Burgdorf Cross, 4 TR 193-94 (only used the worst value).

[84] Burgdorf Cross, 4 TR 193.

[85] *Id.* at 192.

Burgdorf used in his rebuttal projection.[86] The lower number is from the same source as the 2022/23 value that he did use. In other words, Mr. Burgdorf used MISO's projected value for the year 2022/23 as the low end of his range for the year 2025/26 rather than using MISO's projected value <u>for 2025/26 *in the same report*</u>. He stated on cross that he disagreed with MISO's projection for 2025/26 but he never even mentioned in his filed testimony that MISO had a projection for the year he was forecasting, but he was declining to use it and using MISO's projection for a different year instead.[87]

By contrast, MISO used its projected per-unit LRR for 2025/26 to forecast an LRR for Zone 7 that year of 23,857 MW.[88] That is substantially lower than the range of LRRs Mr. Burgdorf's rebuttal forecast of 25,273 to 25,654 MW.[89] MPSC Staff also used MISO's projected LRR of 23,857 MW for 2025/26 in Staff's Capacity Demonstration Report in U-21099.[90] Subtracting Staff's very conservative projected CIL for that year of 3,749 MW from the LRR forecast by MISO produced an LCR for 2025/26 in the Staff report of 20,108 ZRCs. That number is much lower than DTE's projected range of LCRs of 20,385 to 22,454 MW.[91] Subtracting Mr. Burgdorf's projection of Zone 7 resources of 22,145 MW from Staff's projected LCR of 20,108 MW, and then subtracting 1,215 MW for Belle River, yields a <u>surplus</u> of **822 MW** even if Belle River is retired in 2025/26 without adding a single MW of replacement capacity.

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[86] Ex MEC-86, LOLE report for 2022/23, p. 27, Table 6-2.

[87] Burgdorf Cross, 4 TR 194-95.

[88] Ex MEC-86, p. 27, Table 6-2; Burgdorf Cross, 4 TR 196.

[89] Burgdorf Rebuttal, 4 TR 146, Table 7; Ex MEC-79, workpaper titled "WP Zone 7 Resource Forecast – Updated_V2," p. 1. See note above about the original version of the table appearing if the testimony is printed.

[90] Ex MEC-82, Staff Report, report p. 7, exhibit p. 10, Figure 4, line 2; Burgdorf Cross, 4 TR 196.

[91] Burgdorf Rebuttal, 4 TR 146, Table 7; Ex MEC-79, workpaper titled "WP Zone 7 Resource Forecast – Updated_V2," p. 1. See note above about the original version of the original version of the table appearing if the testimony is printed.

Line 6 – Zone 7 resources. Next, Mr. Burgdorf doubled the MW of DTE solar projects he assumed would be delayed, from 247 MW to 494 MW.[92] This again was not due to any project-specific information, but rather was meant to reflect a general risk associated with solar development.[93] Mr. Burgdorf simply doubled the size of the risk he had reflected in his original projection. That doubling of solar delay risk lowered Zone 7 resources and made Zone 7 capacity position relative to LCR worse.

Line 4 – CIL. Finally, while Mr. Burgdorf updated the peak demand forecast, per-unit LRR, and solar delay risk in his rebuttal testimony to make the Zone 7 capacity position relative to LCR worse, he declined to use or even mention any updated MISO projections of CIL that would have made the Zone 7 capacity position relative to LCR better. for 25/26. First, in a presentation from March of this year, MISO projection a CIL for Zone 7 in 2026/27 of 5,458 MW and no limit for 2025/26.[94] Mr. Burgdorf asserted that MISO's out-year projections of CIL are not reliable, and DTE entered a 2018 MISO presentation into evidence on redirect as Exhibit A-50 to support this claim.[95] However, MISO made the Exhibit A-50 presentation four years ago, while the Exhibit MEC-89 presentation was made this year. Further, MISO made the 2018 presentation to support a proposal to discontinue the out-year CIL projections, but that proposal was never adopted and MISO has continued making those projections.[96] It would be unrealistic to surmise that MISO would still be making out-year CIL projections if MISO thought they had no value.

[92] Burgdorf Rebuttal, 4 TR 147.

[93] *Id.;* Burgdorf Cross, 4 TR 187-88.

[94] Ex MEC-89, Presentation to Resource Adequacy Subcommittee titled "2026-2027 Out Year CIL CEL Results," Mar. 9, 2022, pp. 3 and 13.

[95] Burgdorf Redirect, 4 TR 211.

[96] Burgdorf Recross, 4 TR 211-12.

The second CIL projection is found in the MISO Michigan Capacity Import/Export Limit Expansion Study.[97] MISO undertook this study at the request of the Michigan Public Service Commission.[98] This study projects a CIL for Zone 7 in 2024 of 5,278 MW in the base case, before any transmission import projects are added.[99] Unlike the March 2022 presentation, DTE offered no evidence to support any assertion that the results of MISO's Michigan CIL study are not reliable or should be disregarded.

Because CIL is subtracted from the LRR to get the LCR, a higher CIL lowers the LCR.[100] Therefore, using or even considering one or both of the MISO projections would have substantially reduced LCR and made Zone 7 capacity position relative to LCR better. DTE's changing of all the assumptions that would worsen Zone 7 resource adequacy, while disregarding the results of two MISO projections that would improve Zone 7 resource adequacy (including study performed at the MPSC's request), is selective and biased and should be given no weight.

In any event, the resource adequacy, replacement capacity, and timing of a Belle River retirement or conversion issues will all be dealt with in the upcoming IRP. All that is at issue in this rate case is whether that IRP analysis should be skewed by approving here the recovery of capital costs that are avoidable in a 2026 Belle River retirement. Or whether customers should be protected from potentially unnecessary costs by disallowing recovery of those avoidable costs for now, with the Company able, if appropriate, to seek recovery in the future. The latter approach is clearly the just and reasonable one for customers.

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[97] Ex MEC-88, Michigan CIL/CEL Expansion Study.

[98] *Id.*, report p. 2, exhibit p. 3.

[99] *Id.*, report pp. 6-7, exhibit pp. 7-8.

[100] Burgdorf Cross, 4 TR 162.

3. **The Commission should deny cost recovery for the Company's Belle River fuel conversion engineering study.[101]**

The Company seeks in this proceeding to recover approximately $2.45 million for fuel conversion engineering at the Belle River plant.[102] Such engineering is part of an effort to potentially convert the Belle River plant from burning coal to combusting gas. In his direct testimony, witness Morren describes the potential conversion "minor and low-cost alteration" that could be completed "expeditious[ly]."[103] To date, the Company has not decided whether to proceed with the gas conversion or to simply retire the Belle River plant.[104] Instead, the Company intends to evaluate the potential conversion in its upcoming IRP.

In his testimony, witness Comings recommended disallowance of the $2.45 million cost for the fuel conversion engineering as premature.[105] In particular, the project appears to be based on the premise that Belle River will be converted to gas, but as noted the Company has not decided to move forward with such conversion.[106] Such a disallowance would be consistent with the Commission's rejection in DTE's 2016 and 2017 rate cases (Case Nos. U-18014 and U-18255,

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[101] MNSC believes the following portions of the record are relevant to the Belle River fuel conversion engineering issue:

- Morren Direct, 5 TR 651;
- Morren Rebuttal, 5 TR 751-52;
- Morren Cross, 5 TR 764-94;
- Comings Direct, 8 TR 4067, 4069;
- Ex. A-12, Sch, B5.1, p. 2; and
- Exs. MEC-70, 106, 107C, 108C, 110, and 111.

[102] Ex. A-12, Schedule B5.1, p. 2, line 2; Morren Direct, 5 TR 651.

[103] Morren Direct, 5 TR 651.

[104] Ex. MEC-70.

[105] ABATE also recommends disallowance of $2.455 million in the bridge year and $18,000 in the projected test year for the Belle River gas conversion engineering because there is no definitive timeline for the project and, therefore, no assurance that any costs would be incurred during the bridge period or projected test year. York Direct Test. at 18-19.

[106] Comings Direct, 8 TR 4069.

respectively) of recovery of planning and engineering costs for a potential future gas plant on the grounds that the Company had not yet decided whether to proceed with the project, that cost should not be rate based until the project is used and useful to customers, and that the issue was better addressed in a Certificate of Need / IRP proceeding regarding the proposed gas plant.[107]

In rebuttal, witness Morren claims that Mr. Comings' opposition to cost recovery for the fuel conversion engineering is based on a misunderstanding of the scope of the project. Mr. Morren explains that the project is not focused on engineering to do the actual conversion but, instead, will provide the information needed to decide whether to move forward with a gas conversion at Belle River.[108] In particular, the fuel conversion engineering project is actually intended to provide a "definitive cost estimate, project scope, and timeline," so that such information can be input into the IRP process where the decision whether to move forward with gas conversion will be made.[109]

The contention that $2.45 million in engineering is intended simply to provide cost, scope, and timeline information that is needed to decide whether to proceed with the gas conversion is questionable at best for at least three reasons. First, at hearing it became clear that much of that information has already been obtained. In particular, the engineering project involves two phases – Phase 1 was an approximately $133,000 feasibility study that was completed in 2021, and Phase 2 is a nearly $3 million engineering report and detailed cost analysis.[110] The feasibility study provided a cost estimate, the steps that would be needed to convert the Belle River boilers to gas, and a timeline for such conversion.[111] When asked why the information regarding cost, scope, and timeline in the feasibility study was not sufficient, Mr. Morren claimed that the feasibility study

[107] Case No. U-18014, Jan. 31, 2017, Order, at p. 21; Case No. U-18255, Apr. 18, 2018, Order, at pp. 8-9.

[108] Morren Rebuttal, 5 TR 752.

[109] *Id.*

[110] Morren Cross, 5 TR 772, 774-77.

[111] *Id*. at 787-92.

focused only on the boilers and, therefore, did not cover all of the auxiliary equipment and gas infrastructure that would be needed as part of the conversion.[112] Witness Morren conceded, however, that the boiler is a "big piece of the conversion" and that the feasibility study provided sufficient basis for Mr. Morren to testify in his direct testimony that the conversion would be "low-cost," "minor," and "expeditious."[113]

Second, the Phase 2 engineering study would appear to go far beyond simply providing a cost estimate, scope, and timeline for a gas conversion. For example, the PMP for the engineering study lists 25 different tasks as included in the scope for the project, only one of which even mentions project planning or scheduling.[114] Consistent with the wide array of tasks included in the scope, the draft engineering study that the Company received was approximately 750 pages long,[115] not including the detailed cost analysis that apparently is still underway.[116] DTE has provided no explanation for why this level of detail and cost is necessary to evaluate a potential Belle River gas conversion in the upcoming IRP.

Third, it seems quite doubtful that the information being gathered through Phase 2 of the engineering would even be received in time to incorporate into the IRP. As previously noted, the IRP is expected to be filed in October, and there are undoubtedly months of modeling, analysis, and stakeholder engagement that occurs beforehand. Yet, Mr. Morren acknowledged that the Company received the 750-page draft Phase 2 engineering study only a few days before the hearing, and anticipated that they would receive the draft detailed cost analysis in the "next month

[112] *Id.* at 788.

[113] *Id.* at 789-94.

[114] Ex. MEC-111 at p. 3.

[115] Morren Cross, 5 TR 772.

[116] *Id.* at 777.

or so."[117] With the IRP filing expected within approximately three months, it is unclear how any of the Phase 2 information will even be finalized before the IRP is filed much less meaningfully incorporated into the analyses therein.

When DTE sought in its 2016 rate case cost recovery for $13.2 million in planning and engineering for a potential future $1 billion gas plant, the Company claimed that such expenditure was needed to "determine the size, location, and cost of a new gas-fired plant and that this information must be obtained before filing a CON."[118] The Commission apparently rejected that contention in disallowing the requested cost recovery. The Commission should do the same here.

B. Distribution Operations Total Capital

1. Introduction to this section

DTE Electric proposes enormous increases in distribution operations capital in the test year.[119] DTE proposes to increase overall distribution capital spending from $904 million in historic year 2020 to $1,425 million in test year ending Oct. 31, 2023. This would be an increase of $520 million, or a 58% increase.[120] The most significant increases are in Strategic Capital Programs, as supported by DTE Electric witness Sharon Pfeuffer, particularly Infrastructure Resilience and Hardening, Infrastructure Redesign and Modernization, and Technology and Automation.[121] These three programs collectively account for $490 million of the $520 million

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[117] *Id.* at 779-780.

[118] Case No. U-18014, Jan. 31, 2017, Order, at p. 20.

[119] Ex A-12, Sch B5.4, p. 1 of 12.

[120] *Id.* p. 1, line 23. 520/904 = 0.575.

[121] Direct Testimony of Sharon G. Pfeuffer, 4 TR 289-369.

increase in distribution capital spending, or 54% of the proposed total distribution capital spending increase.[122]

MNSC witness Robert Ozar proposed disallowances in three subprograms in Strategic Capital Programs. In the Infrastructure Resilience and Hardening subprogram, Mr. Ozar recommended the Commission disallow increased investments in the 4.8kV Hardening and Pole and Pole Top Maintenance and Modernization (Pole/PTMM) subprograms beyond 2021 spending levels. In the Infrastructure Redesign and Modernization subprogram, Mr. Ozar recommended the Commission disallow further investments in the Strategic and Service Undergrounding pilot. MNSC support Strategic Capital disallowances as follows (in thousands):

	2021	**2022**		**Test Year Ending 10/31/2023**	
		Proposed	Disallow	Proposed	Disallow
4.8kV Hardening Ex A-12 Sch B5.4 p8 line 9	$68,246	$115,857	$47,611	$114,310	$46,064
Pole/PTMM p8 line 10	$33,444	$59,912	$26,248	$87,735	$54,291
Strategic & Service Undergrounding Ex A-12 Sch B5.4 p10 line 87	$306	$258,178	$257,178[123]	$314,334	$314,334
Total	***$101,996***	***$433,947***	***$331,037***	***$516,379***	***$414,689***

[122] Ex A-12, Sch B5.4, p. 1, line 22. 490/904 = 0.54.

[123] Mr. Ozar recommended approving $1 million to fund a comprehensive study of lifecycle costs of both underground and overhead distribution systems and other preliminary assessments, as discussed below.

Mr. Ozar also addressed other issues related to distribution system investments and improvements, which are addressed in other parts of this brief per the *Disputed Issues Chart* circulated in this proceeding. These include contribution in aid of construction (CIAC) policy reform (addressed in **Rate Design & Tariff Issues**), capital investments that should be considered operating expenses (addressed in **Other Revenue Related Items**), a new incipient failure detection pilot (addressed in **Future Rate Cases, Further Study, Other**), and a customer survey and local updates to more accurately quantify value of reliability (also addressed in **Future Rate Cases, Further Study, Other**).

The sections that follow address the Company's proposed investments, and Mr. Ozar's proposed disallowances, related to the 4.8 kV Hardening program, the Pole/PTMM program, and the Strategic Undergrounding pilot.

Unifying Mr. Ozar's recommended disallowances in these three programs is his concern that the Company has insufficiently demonstrated an asset replacement strategy that is properly focused on those assets that have already failed or are in imminent risk of failure.[124] This second category, which Mr. Ozar refers to as "preemptive replacement," is the source of the tension between the Company's proposed investments and Mr. Ozar's proposed disallowances. Mr. Ozar testified that the Company has adopted a *proactive* rather than a *preemptive* approach to replacement. For example, the 4.8kV Hardening program replaces all wooden crossarms (and then the pole top equipment attached to it), without regard to the condition of the crossarm. The Company indicates that it does not *repair* are part of the Hardening and PTMM program, it *replaces*. This proactive replacement approach biases towards capital spending and leads to a swollen capex investment.

[124] Ozar Direct, 8 TR 3961-3966.

Mr. Ozar cautioned that a "proactive" replacement warrants a substantial demonstration of cost effectiveness, much more so than a traditional failure/imminent failure maintenance policy in order to protect customers against the lost value of unreasonable early retirement of historical investments.[125] In addition, Mr. Ozar noted that the radical increase in distribution asset replacement suggests either a system in crisis due to long-term lack of maintenance or, more likely, an opportunistic investment to grow rate base.[126] The magnitude of increased replacements in Hardening and PTMM warrant careful scrutiny. The promise of reliability benefits should likewise be carefully reviewed, and correlated to replacements (rather than tree trimming). Rather than increasing the proposed Hardening and PTMM investments, course corrections may instead support revisions to tree trimming or acceleration of the conversion program.[127]

[125] Ozar Direct, 8 TR 3963.

[126] *Id.* at 3964.

[127] *Id.* at 3965, 3966.

2. 4.8kV Hardening[128]

a. Introduction to this subsection

DTE Electric witness Sharon Pfeuffer presented the Company's proposed 4.8kV Hardening program investment.[129] In sum, her direct testimony discussed program components, emphasized safety and reliability improvements, described proposed ramp-up in miles hardened, summarized the Commission's initial approval in Case No. U-20162, and presented the first two years of data assessing hardening reliability and safety (2018 and 2019).[130]

Mr. Ozar addressed the Company's supporting testimony and additional evidence obtained through discovery, which undermine the Company's proposed increase in hardening spending starting in 2022.[131] Without reiterating his analysis and concerns, Mr. Ozar addressed the regulatory context for the hardening program (U-20162 and U-20561); presented the annual program spending; and explained several inadequacies in the Company's "effectiveness"

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[128] The record regarding Hardening is as follows:

- Pfeuffer Direct, 4 TR 290-300;
- Pfeuffer Rebuttal, 4 TR 421-428;
- Pfeuffer Cross, 4 TR 544-90;
- Ex A-12, Sch B5.4;
- Ex A-23, Sch M1 (Dist. Grid Plan), pp. 241-247 of 568;
- Ex A-23, M4 Revised;
- Becker Direct, 8 TR 5409-5413;
- Ex S-15.3;
- Coppola Direct, 8 TR 4757-4761;
- Ozar Direct, 8 TR 3967-3983;
- Exs MEC-19, 20, 21, 22, 26, 27, 31, 34, 35, 90, 91, 92, 93, 94, 95, 96 97, 98, 102, 105;
- Koeppel Direct, 8 TR 4307-4329;
- Exs DAO-53, 69, 71;
- York Direct, 8 TR 3037-3039.

[129] Pfeuffer Direct, 4 TR 290-98.

[130] *Id.* at pp. 296-97; see also Pfeuffer Cross, 4 TR 550.

[131] Ozar Direct, 8 TR 3967-83.

analyses.[132] Among others, Mr. Ozar explained a core deficiency in the Company's analysis of the effectiveness of hardening, from both reliability and safety perspectives, is that the Company failed to isolate the benefits of tree trimming from the benefits of "asset replacement" – especially cross-arm then pole top equipment replacements – that are the core of the hardening program.[133] Overlaying the concern discussed in the preceding section – that significant capital investments in preemptive repairs should be paired with a clear demonstration of cost-effectiveness – Mr. Ozar opined that the Company's case for increasing hardening spending falls far short. The Company simply failed to demonstrate the cost effectiveness of hardening – independent of tree trimming.[134] Mr. Ozar recommended that the Commission disallow the proposed expansion of the hardening investment in the bridge and test years, instead caping approved spending in those years at the 2021 spending level ($68.246 million).[135] This results in disallowances of $47.612 million in 2022 and $45.754 million for the test year.[136]

Witness Pfeuffer addressed Mr. Ozar's concerns and recommendations in rebuttal.[137] None of the rebuttal arguments alter the strength of Mr. Ozar's testimony and arguments, nor support the Company's proposal to increase its investment in 4.8 kV hardening in 2022 and beyond.

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[132] The Company provided in discovery an updated effectiveness study for circuits hardened in 2020. See Ex MEC-22; Pfeuffer Cross, 4 TR 551 (2020 analysis).

[133] Ozar Direct, 8 TR 3973-83.

[134] *Id.* at 3982-83.

[135] Mr. Ozar noted that the Company's actual 2021 spending for hardening was $66.246 million. See Ozar Direct, 8 TR _3958; but see *id.* at 3970 ($68 million spending in 2021). According to Ex A-12, Sch B5.4, p. 8, line 9, the Company's 2021 spending for 4.8 kV Hardening was $68.246 million; the reference in Mr. Ozar's testimony to $66.246 million appears to be a typographical error.

[136] Ex A-12, Sch B5.4, p. 8, line 9 (col (d) 2022 spend $115.857 – col (c) 2021 spend $68.246 = $47.612; col (e) test year ending 10/31/2023 spend $114.0 – col (c) 2021 spend $68.246 = $45.754).

[137] Pfeuffer Rebuttal, 4 TR 423-428.

b. <u>Prior Company analysis and Commission rate case orders do not support the Company's requested spending increases for hardening in this proceeding.</u>

Ms. Pfeuffer suggested that MNSC ignores Commission precedent addressing the hardening program.[138] This is an ironic argument: Ms. Pfeuffer apparently ignored Mr. Ozar's testimony in this case that specifically and directly addresses both U-20162 and U-20561.[139]

The suggestions that the Company already analyzed the 4.8kV hardening program and the Commission already found the program cost-effective in Case No. U-20162 are also misleading.[140] In that case, the Commission considered whether the initial proposed investment for 2018 and 2019 were reasonable and prudent. The record in U-20162 related to hardening includes testimony by DTE witness Bruzzano, who presented a description of hardening and a comparison of hardening to conversion, pre-conversion, and a "secondary program" – all of which were orders of magnitude more costly than hardening.[141] Mr. Bruzzano did not indicate in his testimony that the Company considered less expensive enhanced tree trimming to provide reliability and safety improvements. And he did not address planned ramping up in 2022 or beyond. To the contrary, in testimony, Mr. Bruzzano indicated that the "Directional 2020-2022 Scope" for hardening was "~600 miles of overhead circuit miles."[142] The Company has hardened about 600 miles so far. There are also considerable spending differences from 2018 to 2023:[143]

[138] Pfeuffer Rebuttal, 4 TR 423.

[139] Ozar Direct, 8 TR 3968-69.

[140] Pfeuffer Direct, 4 TR 423-25.

[141] Ex MEC-92, p. 14 (U-20162, Bruzzano Direct, 4 TR 730).

[142] Case No. U-20162, Bruzzano Direct, 4 TR 806.

[143] Ozar Direct, 8 TR 3970.

2018	2019	2020	2021 Projected	2022 Projected	2023 Projected
$40 million	$58 million	$55 million	$68 million	$116 million	$114 million

The record in U-20162 does not suggest the Company already addressed the issues related to the effectiveness of hardening raised by MNSC in this case. In that case, U-20162, Soulardarity argued in favor of conversion rather than hardening. The Commission only concluded that hardening would be more prudent than conversion – not that hardening was the most prudent means of improving reliability:

> Soulardarity makes some important points about the importance of ensuring safe, reliable service for all ratepayers. The 4.8 kV system is not limited to the city of Detroit, and extends to the suburbs and the Thumb area served by DTE Electric. It is an aging system that will be very expensive to completely replace. It is not feasible to do this all at once. DTE Electric has developed a risk-based approach to convert certain areas to 13.2 kV and harden other parts of the existing 4.8 kV system to ensure safer, more reliable conditions until the full conversion can take place. It is important to remember that the Commission must consider the interests of all ratepayers and the cost burden imposed by each expenditure decision. <u>All expenditures must be reasonable and prudent, and, as the ALJ explains, it is currently impossible to find that the cost of conversion of the entire system to 13.2 kV is reasonable and prudent in light of the fact that 80% of the service quality improvement that can be expected from conversion can be obtained for about 16% of the cost through hardening</u>. The Commission is working to improve conditions in Detroit through its decisions on system hardening and tree trimming,[144] as well as the investigations related to billing and the need to address the presence of arc wire in the city. As Soulardarity points out, all ratepayers should be subject only to rates that result in reasonable and prudent investments in safety and reliability. The Commission adopts the findings and recommendations of the ALJ.[145]

144 The Commission is requiring DTE Electric to provide regular reporting on tree trimming efforts in the city of Detroit and in the Caniff Service Center area.

145 Case No. U-20162, May 2, 2019, Order, p. 33 (emphasis added).

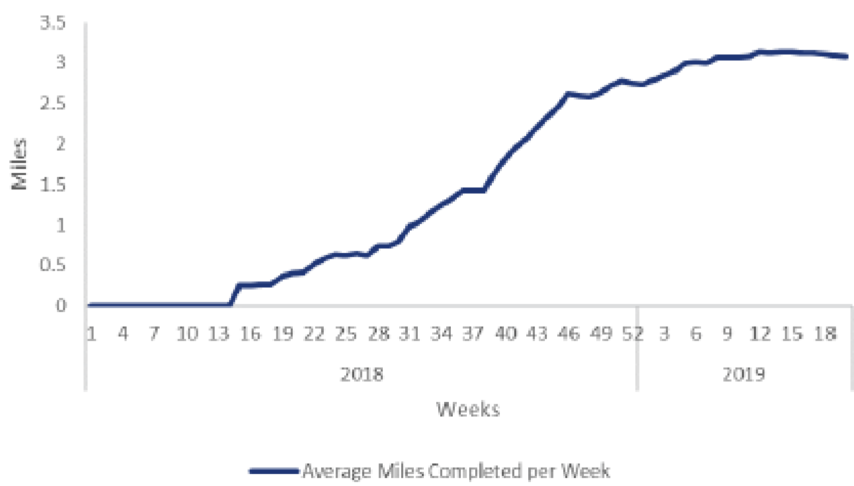
The Commission did not address the ramp up, nor the actual results of hardening, nor whether those benefits may be achieved with less costly maintenance than hardening.

In U-20561, it was too soon for the Company to provide effectiveness data associated with hardening, but the Company provided a progress report with a status update for 2018 and 2019:[146]

167

M. A. BRUZZANO
U-20561

Figure 8 4.8kV Hardening Average Miles Completed per Week 2018-2019



Mr. Bruzzano did not address ramping up hardening miles and spending in U-20561.

In response to Soulardarity's renewed concerns about hardening versus conversion, the ALJ in U-20561 noted that the Commission had addressed concerns about hardening versus conversion in U-20162, but noted the importance of greater transparency related to DTE's decision-making about which circuits are to be hardened.[147] The Commission agreed that it had addressed similar concerns (hardening versus conversion) in U-20162, and also that DTE should provide "a more detailed explanation of the factors and scoring process" used to prioritize circuits

[146] Ex MEC-92, p. 17; see also Case No. U-20162, Bruzzano Direct, 4 TR 168 (discussing program effectiveness).

[147] Case No. U-20561, Mar. 5, 2020, Order, p. 193.

to be hardened, together with a plan and timeline for system hardening and conversion in the next distribution plan.[148]

This is thus the first contested proceeding to consider evidence of the effectiveness of hardening, in terms of actual safety and reliability benefits. Until the Company had hardened some miles and reviewed some comparison data, the Commission had limited information to evaluate effectiveness. This case is the first opportunity for the Company to present, for stakeholders to test, and for the Commission to evaluate, whether in fact hardening is as effective as the Company, Commission, and stakeholders may have hoped it would be in U-20162 and U-20561.

It is also the first opportunity for the Commission to consider the *cost*-effectiveness of hardening. Unfortunately, the Company has maintained insufficient records for the Commission to evaluate cost-effectiveness of hardening.[149] While DTE provided data regarding the number of events, outage minutes, and wire-downs per circuit before and after hardening, DTE was unable to provide cost-per-circuit data necessary to assess cost-effectiveness.[150]

This is also the first opportunity to compare the effectiveness and cost of hardening to enhanced tree trimming and maintenance. As Mr. Ozar testified, the Company and Commission in U-20162 and U-20561 considered hardening vis-à-vis *more* costly options, not relative to *less* costly opportunities.[151]

This is also the first contested proceeding for the Commission to consider DTE's proposal to substantially increase the number of miles hardened and the dollars it proposes to spend to do so. In the two prior rate cases, the Commission considered DTE Electric's hardening plans for

[148] Case No. U-20561, May 8, 2020, Order, pp. 110-111.

[149] Ozar Direct, 8 TR 3982.

[150] *Id*., citing Exs MEC-35, 32.

[151] Ozar Direct, 8 TR 3969.

2018 through 2021, but not its plans to expand hardening into 2022, which is when the ramp-up would begin. It appears the details of the Company plans for hardening expansion are somewhat flexible. In the 2021 Grid Distribution Plan, filed September 30, 2021, in U-20147, the Company proposed to increasing hardening in 2022 by 92% over the miles hardened in 2021.[152] Then in this rate case, the Company proposed a 79% increase in hardened line miles.[153]

	Line Miles 2021	**Line Miles 2022**	**Change**
2021 Grid Plan	195	195	92%
2022 Rate Case	195	350	79%

Obviously, plans change. The point is that the Commission didn't and couldn't assess program effectiveness nor approve the proposed 2022 ramp up in hardening miles or spending before now.

The question of whether to increase hardening is thus a novel and ripe issue for this case. With three years of hardening data now available, with no data to assess cost-effectiveness, with notable consistency between hardening and enhanced tree trimming effectiveness, with high capital costs associated with hardening versus trimming, and given the proposed increase in hardening spending, it is appropriate and timely for the Commission in this case to reject DTE's proposal to expand and increase hardening.

c. The Commission has not ordered DTE Electric to remove DPLD-owned arc wire, and there is no demonstrated correlation between DPLD-owned arc wire removal and safety and/or reliability on hardened circuits.

The Company justifies its hardening investment in part by reference to an "MPSC requirement" for the Company to remove DPLD arc wire, referencing Case No. U-18484.[154] This

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[152] Ex A-23, Sch M1, p. 247 of 568, Exhibit 9.3.4.1.

[153] Pfeuffer Direct, 4 TR 294, Fig. 13.

[154] Pfeuffer Rebuttal, 4 TR 424-26; Pfeuffer Cross, 4 TR 559-561 (discussing Commission directive to remove arc wire).

position misstates the Commission's approach to DPLD arc wire removal, which requires DTE Electric to properly maintain its distribution lines, including where its equipment is co-located with DPLD arc wire. The Company turns that obligation on its head when it suggests arc wire removal justifies the hardening investment.

Review of U-18484 shows DTE minimized the hazards of arc wire and opposed arc-wire removal obligation, Staff became aware of extensive overgrown vegetation along Detroit circuits, and the Commission did not mandate DTE remove arc wire but insisted DTE improve system safety through proper line clearing and accepted DTE's commitment to track and report arc wire removal. The docket in U-18484 is summarized below.

September 16, 2016: A terrible and tragic accident occurred in Detroit when DPLD arc wires[155] detached and lay across DTE Electric primary lines, hung down in trees and on the ground, and led to the electrocution of a child.[156]

September 23, 2016: The Commission opened an investigation into the accident.[157]

December 7, 2017: The Commission closed its docket investigating the accident and opened a new docket to monitor and address out-of-service arc wire issues.[158] In discussing obstacles to arc wire removal, the Commission noted as follows:

> The Staff participated in a field tour of an area where there is out-of-service arc wire, and found widespread areas of overgrown brush, small saplings, and abandoned buildings. In those areas, the Staff recommends that, for the safety and accessibility of electric crews, the vegetation must be cleared and hazards addressed prior to working on the lines. [159]

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[155] Arc power lines or arc wires that were formly used to supply electricity to arc-type street lamps. See Case No. U-18484, Mar. 14, 2018, Order, p. 2, n. 1.

[156] See Case No U-18172, Dec. 7, 2017, Order.

[157] See Case No. U-18172, Sep. 23, 2016, Order.

[158] Case No. U-18172, Dec. 7, 2017, Order, p. 7; Case No. U-18484, Dec. 7, 2017, Order.

[159] Case No. U-18484, Dec. 7, 2017, Order, p. 3.

The Commission ordered DTE to work with Staff, DPLD, and other relevant entities, "to accomplish a long-term, comprehensive plan to address out-of-service arc wire in Detroit."[160] In particular, the Commission requested an initial assessment by March 30, 2018, developed in collaboration with Staff and DPLD, documenting how much wire remains, where it is located, where it can be easily removed, and where overgrown vegetation and other obstacles impose barriers to removal.

January 8, 2018: DTE Electric filed for rehearing of the December order, arguing:

> DTE Electric does not own, operate, or have any legal rights or obligations whatsoever to the DPLD arc wire – it is owned by DPLD and the Commission recognizes this in the Order. As such, the Company cannot be compelled by Commission Order to remove equipment over which it has no ownership or control and no express authority to remove. Furthermore, DTE Electric has no power to obligate DPLD to undertake any specific action with respect to arc wire removal.[161]

DTE advocated instead for a voluntary approach to address arc wire using its proposed 4.8kV fault identification system and planned distribution upgrades.

March 15, 2018: The Commission recognized DTE does not own the arc wire and has no independent authority over arc wire, but noted its regulatory authority to require DTE to maintain adequate line clearance, which can affect the likelihood of downed wires and hazards.[162] The Commission specifically clarified that its December order was *not* "a directive to remove arc wire."[163] The Commission modified its order to clarify that DTE must maintain its facilities in a manner that protects the safety of the public and its employees, and that "it is essential that the company have a sense of urgency and commitment to address any safety concerns."[164]

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[160] Case No. U-18484, Dec. 7, 2017, Order, p. 5.

[161] Case No. U-18484, Jan. 8, 2018, Petition for Rehearing, p. 3.

[162] Case No. U-18484, Mar. 15, 2018, Order, p. 4.

[163] *Id.*

[164] *Id.* at p. 5.

March 29, 2018: DTE submitted its *Plan to Address Arc Wire*, indicating 4.8kV hardening may remove about 650 line-miles of arc wire collocated on DTE facilities over 10 years.[165]

July 31, 2018: Staff filed its *Response to DTE Electric's Arc Wire Report*, noting that "[r]ecently, Staff became aware of that tree density is high in the city of Detroit, and a program to rectify this condition must occur while hardening and conversion to 13.2 kV is occurring."[166] Staff recommended DTE provide more detail about circuits to be converted and hardened and file annual reports of hardening spending, including circuits hardened, how much arc wire was removed, upcoming hardening and a tabulation of how many miles of arc wire were removed under various programs.[167] Staff also raised concern about DTE ratepayers paying for DPLD arc wire removal.[168]

August 31, 2018: DTE filed its Response to Staff Report, committing to provide annual reports by the end of the first quarter for the previous year's work; documenting spending, circuits hardened, miles of arc wire removed, changed plans, and number of cross arms removed; and tabulating arc wire removal under each program (hardening, conversion, CEMI).[169] DTE also reiterated that "arc wire on its own is not a hazard,"[170] and instead the Company focuses on total wire downs – whether arc wire or otherwise – to assess safety risk and prioritize resources.

September 28, 2018: The Commission issued a final order closing the docket. The Commission noted remaining concerns with "the dangers posed to the public by abandoned arc wire juxtaposed with overgrown vegetation, obstructed or limited access to alleyways, and the

[165] Case No. U-18484, Mar. 29, 2018, Plan; see also Ex MEC-92, p. 8.

[166] Case No. U-18484, July 31, 2018, Staff Report, p. 4.

[167] *Id.*, p. 7.

[168] *Id.*

[169] Case No. U-18484, Aug. 21, 2018, DTE Report, pp. 20-21.

[170] *Id.*, p. 12.

declining ungrounded 4.8kV system."[171] The Commission declined to approve any issues in the docket, reserving "performance expectations and cost recovery" for DTE's pending rate case (Case No. U-20162).[172]

There was no directive in U-1848 to remove arc wire. To the extent the Commission approved and may continue to approve ratepayer investment in hardening in rate cases, DTE agreed the program would include DPLD arc wire removal because that would be more cost effective than conversion, arc wire removal alone, and other approaches considered.[173] At the same time, DTE was clear that hardening "will also allow for the removal of DPLD arc wire where it is co-located with DTE Electric's assets, though *the removal of arc wire is not the primary driver nor the primary benefit of this program*."[174] It is now illogical for the Company to support approval of its proposed ramp-up in hardening *because* it also will remove co-located arc wire it comes across in the process. The Company must demonstrate that hardening is a cost-effective way to maintain the distribution system to prevent safety risks, including downed wires – arc or otherwise. Removing arc wire may be a benefit of hardening, but it does not convert hardening into a reasonable and prudent ratepayer investment.

Besides noting that DTE mischaracterized U-18484 as imposing a "requirement" to remove arc wire that helps justify its hardening investment, it is also notable that the Company has apparently not complied with other aspects of the U-18484 docket. DTE has not provided annual reports with the metrics it agreed in U-18484 to provide.[175] In U-20162, DTE had not yet

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[171] Case No. U-18484, Sep. 28, 2028, Order, p. 6 (emphasis added).

[172] *Id.*

[173] Case No. U-18484, Aug. 21, 2018, DTE Report, pp. 9-10, Table 1.

[174] Ex MEC-92, p. 13 (Case No. U-20162, Bruzzano Direct, 4 TR 729).

[175] Ex MEC-92 (requesting arc wire removal reports and referencing 2018 Plan and testimony in U-20162 and U-20561).

completed hardening so there was no report to provide. In U-20561, DTE identified the total miles hardened and dollars spent on hardening (70 miles, and $40 million),[176] but failed to provide a tabulation of miles of arc wires removed under various programs. DTE indicated it "has reviewed the progress of the arc wire removal at various times with the Staff and the Commission through ad hoc meetings,"[177] but that is not the reporting it agreed to provide in U-18484. In this case, DTE barely mentioned arc wire removal until it filed rebuttal testimony that cited arc wire removal as justification for the hardening program. It was not until discovery following that rebuttal testimony that DTE provided a tabulation of miles of arc wire removed since 2018.[178] As discussed below, that general information is insufficient to assess removal progress or program effectiveness.

It is also worth noting that *how* DTE tracks arc wire removal is ambiguous. In discovery, DTE claimed it cannot identify hardened circuits where arc wire was removed because it does not track arc wire removal at the circuit level.[179] DTE then contradictorily asserted that it does track arc wire removal through design surveys, separate and apart from inspection reports that were provided in discovery.[180] Further contradictorily, DTE also claimed that arc wire removal information is tracked by span notations in dense, confidential construction invoices identifying "small wire."[181] It appears "small wire" covers several gauge sizes besides arc wire.[182] Then at the

[176] Ex MEC-92, pp. 1, 17.

[177] Ex MEC-92, p. 1.

[178] Ex MEC-105, pp. 1-2.

[179] Ex MEC-105, p. 3.

[180] Ex MEC-90, p. 4 (arc wire survey done under design step of hardening process); Pfeuffer Cross, 4 TR 566 ("the arc wire survey does identify the number of spans of arc wire on the circuit."); *id.* at 569 (arc wire survey is part of design).

[181] Ex MEC-105, p. 4 (arc wire supporting documentation in construction invoices); Pfeuffer Cross, 4 TR 570-73.

[182] Ex A-23, Sch M1 (2021 DGP), p. 186 of 568 (discussing various wire gauges, no mention of "arc wire" among the various "small wires").

hearing, Ms. Pfeuffer stated the Company can identify arc wire removal by "span by circuit," but not by line miles or feet by circuit.[183] To track where arc wire was removed and how much was removed, DTE alone (since the data is proprietary) might be able to review thousands of line-entries in construction invoices to identify where "small wire" was removed, which may include arc wire. DTE does not track costs associated with arc wire removal at all.[184] This is a far cry from transparent reporting. It is virtually impossible for the Commission and stakeholders to understand with any level of confidence how much arc wire has been removed and is left, the costs associated with arc wire removal, and any correlated reliability and safety benefits.

Without information about where arc wire has been removed and remains to be removed, and how much it costs to remove it, it is not possible to assess the cost or cost effectiveness of arc wire removal, nor whether arc wire removal is a reasonable ratepayer investment. And it is not possible to ascertain whether there were increased safety risks associated with arc wire (are there more wire down events associated with arc wire versus non-arc wire circuit segments?), nor whether the removal reduced wire downs associated with arc wire. Arc wire removal thus remains a black box in terms of progress, cost, cost-effectiveness, safety risks, and safety improvements. Absent more information, arc wire removal cannot justify the Company proposed increases in hardening investments in the bridge and test year. The Commission should not accept DTE's attempt to wield DPLD arc wire removal as a sword to ward off careful consideration of the effectiveness of hardening and the prudency of its proposed increased hardening investment.

[183] Pfeuffer Cross, 4 TR 576-77.

[184] Ex MEC-91.

d. Hardening that achieves reliability & safety benefits at an excessive and unreasonable cost is not redeemed by being included in an environmental justice plan.

DTE states in rebuttal that hardening improves reliability and safety in the near term in the part of the distribution system that services impacted communities, and that hardening is expected to be included in the Company's environmental justice plan.[185] The implication of this argument appears to be that the Commission should approve the Company's proposal to increase hardening in Detroit because hardening improves safety and reliability for environmental justice communities.

MNSC unequivocally supports improving safety and reliability for the part of the distribution system that is in environmental justice communities. DTE has not, however, shown that hardening – an expensive "capital" program – improves safety and reliability above and beyond proper line clearing, such as through the enhanced tree trimming program. The Commission should not approve very high levels of capital spending on a program that achieves safety and reliability at levels on par with maintenance tree trimming. It seems that what makes hardening so costly is cross-arm replacement – all wooden cross arms are replaced with fiberglass, which necessitates new pole top equipment.[186] Yet DTE's data shows that equipment generally causes only about 10% of SAIDI interruptions,[187] and cross arms in particular, are miniscule causes of customer interruptions – only about 0.281% of customer-minute interruptions (SAIDI) are associated with cross arm issues.[188] For lines that were hardened, DTE's data suggests that equipment was much less of a cause of outages on hardened lines (4%) than on the system

[185] Pfeuffer Rebuttal, 4 TR 425.

[186] Ex MEC-26, MEC-20; Ex MEC-21.

[187] Ozar Direct, 8 TR 3979; Ex MEC-34; see also Ozar Direct, 8 TR 3981.

[188] Ozar Direct, 8 TR 3980.

generally (about 10%).[189] Thus, DTE has not justified a program that focuses on replacing wooden cross arms – whether in environmental justice areas or other areas.

Meanwhile, vegetation management is the most substantial cause of reliability and safety issues associated with the distribution system, including in Detroit.[190] In initially proposing the hardening program, DTE noted that there is a higher volume of trouble events in Detroit, which is driven by infrastructure age and "exacerbated by the abandoned and overgrown alleys in the City of Detroit."[191] Prior to their "hardening" trim, the 18 of 28 circuits lines "hardened" in 2020 had not been trimmed since 2011, 7 were hardened in 2012, and the rest were hardened in 2007 or 2010.[192] It is not surprising they experienced safety and reliability improvements following hardening that included trimming.

DTE has not supported its proposal to increase spending in the hardening program in the bridge and test years because the Company has not demonstrated that hardening (as opposed to enhanced line clearing) improves the reliability and safety of the system.[193]

e. The Company has not demonstrated that hardening independent of line clearing provides significant safety and reliability benefits to customers.

The Company's next rebuttal argument in response to Mr. Ozar's concerns about the hardening ramp-up is that the Company has hardened over 600 line-miles already, and hardened lines saw significant improvements over non-hardened areas.[194] In support, the testimony references the Figures 14, 15, and 16 on pages 73 and 74 (4 TR 296-97) of Ms. Pfeuffer's direct

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[189] Ozar Direct, 8 TR 3981.

[190] Ex A-23 Sch M1 (GDP), p. 11 of 568 ("Historically, trees cause two-thirds of the time (outage minutes) our customers spend without power.");

[191] Ex MEC-92, p. 12 (U-20162, Bruzzano Direct, 4 TR 728).

[192] Ex MEC-96.

[193] Ozar Direct, 8 TR 3973-76.

[194] Pfeuffer Rebuttal, 4 TR 426.

testimony. The Company further asserts that tree trimming alone would not achieve the benefits of hardening: arc wire removal and safety and the duration of customers outages.[195] In support of this assertion, the Company asserts that hardening has been more effective at reducing SAIDI ex-MEDs and wire downs than tree trimming.

Mr. Ozar fully addressed the flaws and deficiencies in the Company's "effectiveness" assessment in his direct testimony.[196] The Company's assessment included two distinct treatments: trimming and "hardening," such that it is impossible to assess whether safety and reliability benefits are the result of trimming or hardening. The reported benefits of "trimming + hardening" are similar to the benefits of trimming alone.[197] The Company did not rebut these flaws. The Company has not demonstrated the effectiveness of hardening relative to a control group.

The Company's argument that hardening is more effective than tree trimming alone is also unsupported on the record. The Company references the table in Mr. Ozar's testimony, page 25 (8 TR 3978) to assert that hardening is 47% better at reducing SAIDI ex-MEDs than trimming, and 56% at reducing wire downs than trimming along.[198] The Company's more recent assessment of the effectiveness of tree trimming shows one-year after improvements on par with hardening:

[195] *Id.* at 426-27.

[196] Ozar Direct, 8 TR 3972-83.

[197] Ozar Direct, 8 TR 3979.

[198] Pfeuffer Direct, 4 TR 427 (referencing Ozar Direct, 8 TR 3978).

	Hardening[199]	Tree Trimming (ETTP)	
		2020 Report[200]	2021 Report[201]
All-Weather SAIFI/ Customer Interruptions	32%	34%	46%
SAIDI Ex-MEDs / Customer Minutes of Interruptions	66%	45%	55%
Wire Downs	28%	18%	27%

While the measure of SAIDI ex-MEDs remains higher for hardening than tree trimming, Company witness Hartwick warned, in the context of measuring tree trim effectiveness, that the minutes of customer interruptions "can be more variable because they are impacted by circumstances outside of the control of the tree trim program, including crew availability, travel time to outage, outage prioritization, and accessibility of outage."[202] This relatively higher level of variability associated with SAIDI ex-MED may explain why, in the study of the effectiveness of circuits hardened in 2020, the control group experienced a 33% improvement in SAIDI ex MEDs one year after the "hardened" year – from 205.1 minutes to 137.7 minutes, even though these circuits received neither hardening nor trimming.[203]

A few additional points bear noting related to the Company's assessment of the effectiveness of hardening to date. First, the Company has analyzed hardening effectiveness using the same methodology three times, with notably different results in each assessment. The Company

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[199] Ozar Direct, 8 TR 3978.

[200] *Id.* See also Ex A-31 Sch V1 (2020 Tree Trim Annual Report, filed March 1, 2021).

[201] Ex MEC-97 (2021 Tree Trim Annual Report, filed March 1, 2022).

[202] Hartwick Direct, 7 TR 2296.

[203] Ex MEC-22.

presented its hardening effectiveness analysis for circuits hardened in 2020 in discovery,[204] for circuits hardened in 2018 and 2019 in testimony (Figures 14, 15, 16),[205] and for circuits hardened in 2018 in its 2021 Storm Report filed in U-21122.[206] There is a fair amount of variability, year over year, in both the hardened and control group. This suggests there may be additional variables that influence the outcomes.

It should be noted that the hardening program targets circuits with relatively high numbers of wire-down events.[207] For example, the Company data shows that the average wire-downs per circuit in 2018 for circuits hardened in 2019 was 24,[208] and the average wire-downs per circuit in 2018 for the 2019 control group was 4.[209] Even after hardening, the Company data documents wire down events consistently far in excess of wire down events for circuits in the control group.[210] The Company's data does not demonstrate that hardening is more effective than tree trimming at reducing wire down events, but it does beg further analysis why some circuits have exceedingly high wire downs compared to the balance of the system. DTE has previously suggested that tree density is proportional to increased wire down events.[211]

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[204] Ex MEC-22.

[205] Pfeuffer Direct, 4 TR 296-96.

[206] Case No. U-21122, DTE Electric Company's 2021 Storm Report, filed Oct. 1, 2021.

[207] Compare Ex MEC-93 (wire down events for hardened circuits), to Ex MEC-96 (wire down events for non-hardened circuits).

[208] Ex MEC-93: 752 wire-down events in 2018 for circuits hardened in 2019 divided by 31 circuits hardened in 2019.

[209] Ex MEC-96: 2019 WD Control Grp: 1,274 wire-down events in 2018 divided by 291 circuits in control group.

[210] Ex MEC-93 (hardened circuits wire down events), Ex MEC-96 (control group wire down events).

[211] Case No. U-18484, Aug. 31 2018, DTE Reply to Staff Report, p. 3.

It should be further noted that the Company projected that hardening would reduce wire down events by 65% when it argued for hardening versus arc wire removal (Case No. U-18484).[212] The now-available data suggests those projections were unrealistic, and instead reductions are in line with the effectiveness of enhanced trimming.

In sum, the Company has failed to demonstrate that hardening is more effective than line clearing and that it is cost-effective. The Commission should not approve increased spending in this program.

f. <u>The need to rebalance remaining wires following arc wire removal does not justify hardening.</u>

The Company next argues in rebuttal that it cannot replace hardening with arc wire removal because once arc wire is removed, the cross bar must be rebalanced.[213] This argument is misplaced in rebuttal to Mr. Ozar's concerns regarding hardening because he did not advocate for arc wire removal in place of hardening.

Moreover, the need to rebalancing cross-arms following arc wire removal does not appear to impose an obstacle on arc wire removal. In assessing all options to address arc wire in U-18484, the Company considered arc wire removal alone, which would involve wire removal, cross arm rebalancing, and tree trimming (at about one-third the estimated cost of hardening).[214] That arc wire removal requires cross-arm rebalancing does not justify cross-arm replacement, from wood to fiberglass, which is a principal component of hardening. The need for rebalancing after arc wire removal sheds no light on the effectiveness of hardening nor the reasonableness and prudence of the Company's proposed hardening investments.

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[212] Case No. U-18484, Aug. 31 2018, DTE Reply to Staff Report, p. 9, Table 1.

[213] Pfeuffer Rebuttal, 4 TR 427.

[214] Case No. U-18484, Aug. 31 2018, DTE Reply to Staff Report, p. 10.

g. MNSC opposes increasing the hardening investment based on the record in this case.

The Company's final argument in response to Mr. Ozar's testimony regarding hardening is that the program should not be eliminated or reduced because it has been successful and is fully developed.[215] There are two problems with this argument.

First, Mr. Ozar did not recommend eliminating or reducing the program. He recommended the Commission approve spending for the program at 2021 spending levels.[216] The Company proposes to substantially increase program spending; the Company carries the burden of supporting this increase. Mr. Ozar fully demonstrated that the Company failed to do so.

Second, the premise of the Company's position is groundless because the Company did not demonstrate that hardening – above and beyond trimming, which is the first step in hardening – improves safety and reliability for customers. This is the first case where the Company presented effectiveness data, and that data does not allow stakeholders or the Commission to assess the effectiveness of the "hardening" parts of the hardening program – like cross bar replacement – after the circuit is trimmed.

h. Conclusion to this subsection

The Commission should adopt Mr. Ozar's recommendations related to the hardening program. It should maintain the 2021 spending level for this program. It should also require the Company to present an effectiveness study in a future case seeking expanded spending to separate the costs and benefits of the capital replacements included in hardening separate and apart from trimming and maintenance inspections.[217]

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[215] Pfueffer Direct, 4 TR 428.

[216] Ozar Direct, 8 TR 3984.

[217] Ozar Direct, 8 TR 3984.

3. Pole and Pole Top Maintenance and Modernization (Pole/PTMM) Program[218]

a. <u>Introduction to this subsection</u>

Witness Pfeuffer addressed the Company's pole inspection program in her direct testimony.[219] This program was formerly called the Pole and Pole Top Maintenance program. The Company updated its underlying pole specifications and added "Modernization" to the title.[220] This is essentially a program to trim if needed, inspect, and maintain poles and pole top equipment. When the Company identifies degraded poles, it reinforces or replaces them; when it identifies broken or obsolete equipment, it is replaced. The Company proposes to significantly increase spending in this program.[221]

MNSC witness Ozar opposed the Company's planned spending increase in this program.[222] Mr. Ozar raised concerns that the program is pre-defined to undertake pole top *replacements* not *repairs*, which raises concerns related to accounting (capital versus expense, as discussed below in the *Adjusted Net Operating Income* section). He also noted that it was difficult to identify "what changed" related to this program to justify the substantial proposed increase in spending. He addressed each of the rationales proffered by the Company to support the program, and explained

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[218] The record regarding the Pole/PTMM program is as follows:

- Pfeuffer Direct, 4 TR 300-305;
- Pfeuffer Rebuttal, 4 TR 428-32;
- Ex A-12, Sch B5.4;
- Ex A-23, Sch M1 (Dist. Grid Plan), pp. 221-24 of 568;
- Becker Direct, 8 TR 5411-5413;
- Ex S-15.3;
- Ozar Direct, 8 TR 3985-4016; and
- Exs MEC-23, 25, 26, 33, 99, 100, 101, 102.

[219] Pfeuffer Direct, 4 TR 300-305.

[220] Ozar Direct, 8 TR 3986-87.

[221] Ozar Direct, 8 TR 3988.

[222] Ozar Direct, 8 TR 3985-98.

why they did not support substantial spending increases.[223] He considered whether increasing equipment cost justify the expense, but they do not. He noted the Company's approach to setting its spending request is an obscure, "top-down" approach that makes it difficult to understand the rationale for the proposed increased spending level. And he noted that the Company has not evaluated the effectiveness of its program. Finally, he offered a series of recommendations to address the record in this case, and the Pole/PTMM program going forward. He recommended disallowing the expansion of PTMM spending over 2021 levels, the development of a circuit-level cost effectiveness study to support future spending increases, and disclosure of costs associated with enhanced specification materials.[224] He also recommended the Company accelerate the inspection program cycle from a 10-year to a 5-year cycle combined with a program focus on preemptive repairs rather than capital replacements to lower ratepayer costs.[225]

The following sections address the points raised by Ms. Pfeuffer in rebuttal.

b. <u>The Company's 10-year inspection cycle does not justify program spending increases and is should be shortened to a 5-year inspection cycle.</u>

In rebuttal, Ms. Pfeuffer supports the Company's plan to achieve a 10-year inspection cycle (down from 10.9 years),[226] and she recognized benchmarking supports an even shorter inspection cycle.[227] This reiteration of the Company's goal to achieve a 10-year inspection cycle neither justifies the increasing program cost nor is it a sufficient end-goal for this program. Mr. Ozar addressed both points in his direct testimony. The Company's benchmarking supports a four to

[223] *Id.*, 3989-94.

[224] *Id.* at 8 TR 3997.

[225] *Id.* at 8 TR 3997-98.

[226] Pfeuffer Rebuttal, 4 TR 429-30.

[227] *Id.* at 430; see also Ex MEC-33 (benchmarking).

five-year inspection cycle,[228] and Mr. Ozar supported a shorter cycle accordingly. Ms. Pfeuffer quoted Mr. Ozar's testimony supporting a 5-year inspection cycle (4 TR 430) but she did not address the recommendation. The Commission should adopt the recommendation that the Company move towards a short inspection cycle.

As for whether the effort to move from a 10.9- to a 10-year inspection cycle justifies increasing program cost, Mr. Ozar clearly explained why it does not: (a) the Company is already just about at a 10-year cycle (it's a tiny shift over historic cycles); (b) the Company is proposing to shave 0.9 years off the inspection cycle by 2025 – a long time to achieve what the Company has already historically been achieving; (c) inspections are a fraction of program costs, so more inspections are not driving increasing program costs; and (d) it is not clear the Company will be substantially inspecting inspections in the future.[229] The Company did not address any of these issues in rebuttal, instead reiterating the 10-year cycle goal.

c. The "new" pole inspection standard does not justify increasing program costs.

Next, the Company notes that it has changed its inspection process to check for below-grade decay on poles 20 years old and older instead of those 40 years old and older.[230] This is not a new development; the change was implemented in 2019.[231] This means that more poles go through a higher level of inspection than historically were subjected to below-grade decay checks. According to Ms. Pfeuffer, this means more poles need to be remediated.

Mr. Ozar explained that identifying decay earlier should lead to avoided replacements (more costly than reinforcement), which does not justify increasing program costs.[232] Company

[228] Ozar Direct, 8 TR 3997-98; Ex MEC-33.

[229] Ozar Direct, 8 TR 3989-92.

[230] Pfeuffer Direct, 4 TR 431.

[231] Ozar Direct, 8 TR 3994; Ex MEC-101.

[232] Ozar Direct, 8 TR 3992-93.

data provided in rebuttal discovery suggests that, since the more aggressive below grade decay inspection process was implemented in 2019, the number of pole "rejects" as a percent of poles inspected has increased from about 5% (pre-2019) to about 8% (since 2019).[233] However, rejected poles do not necessarily require costly *replacements;* they instead may be *reinforced*.[234] The Company's data shows that pole *replacement* is not projected to increase over historic levels under the "old" inspection process – in fact, it remains well below pole replacement levels in 2017 and 2018 (pre-new standard), while less costly reinforcement increases, consistent with Mr. Ozar's testimony:[235]

	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Replaced Poles	2,700	3,165	2,822	1,431	1,016	1,391	2,191
Reinforced Poles	n/a	2,505	2,717	27	109	3,045	3,220

Moreover, the Company's actual and projected program spending shows that inspections and reinforcements are and will remain a small and relatively static portion of program spending:

[233] Ex MEC-101, p. 1.

[234] Ex MEC-101, p. 2.

[235] Ex MEC-100, p. 2.

U-20836 MNSCDE-6.1b-01 PTMM Program Investments					Bridge Period 22 mos. ending	Test Year 12 mos. ending
		Investment				
Sub-Program	**2020 Actuals**	**2021 Actuals**	**2022 Projected**	**2023 Projected**	**10/31/2022**	**10/31/2023**
Inspections	$110,000	$1,379,000	$5,528,000	$6,016,000	$5,985,667	$5,934,667
Reinforce-ments	$27,000	$121,000	$5,312,000	$5,781,000	$4,547,667	$5,702,833
Line Miles Modernized	$36,227,000	$30,051,000	$48,072,000	$81,703,000	$70,111,000	$76,097,833
Total	$36,364,000	$31,551,000	$58,912,000	$93,500,000	$80,644,333	$87,735,333

The Company's data thus shows that, since the new inspection standard began in 2019, the Company has identified more poles for reinforcement and fewer for replacement, and still reinforcement spending remains a relatively low contributor to increasing program spending. This is consistent with Mr. Ozar's testimony that the newer inspection standard is not likely to justify the substantial cost increase in this program.[236]

d. <u>The higher minimum pole class does not justify increased program spending.</u>

Next in her rebuttal, Ms. Pfeuffer objects to Mr. Ozar's assessment that a higher minimum pole class is also unlikely to justify the increasing program costs.[237] Ms. Pfeuffer asserts that "close to 90% of poles replaced will require the use of the higher-class pole."[238] That many of the replaced poles will be of a higher class than historic poles is not insightful. As Mr. Ozar noted, there is no demonstration that poles are failing and requiring replacement at a rate higher than historically (as discussed above), nor that pole replacement – even at a higher pole class – is driving higher costs.

[236] Ozar Direct, 8 TR 3993.

[237] Pfeuffer Rebuttal, 4 TR 431-32; citing Ozar Direct, 8 TR 3993.

[238] *Id.* at 432.

Mr. Ozar recommended that the Company support costs associated with enhanced specifications for materials (such as minimum pole class).[239] The Company failed to address this recommendation. Absent such data, the Company has not demonstrated the reasonableness of its requested program spending increased.

e. The Company has not shown the Pole/PTMM program is cost effective nor that it is addressing imminent failures.

Finally, Ms. Pfeuffer argues that the Pole/PTMM program is important because it replaces equipment before it fails, so it prevents outages and hazards.[240] This goes to Mr. Ozar's introductory concern: that the Company appears focused on a proactive capital program that is driving up costs.[241] At bottom, it is "line modernizing" that is driving increasing program costs. The program is predisposed and defined to *replace* ("modernize"), even if equipment is not at risk of imminent failure. The Company has not justified its predisposition to replacement rather than repair.

The Company also has not shown that the projected program cost increase is correlated to increasing risk of equipment failure. Spending appears correlated to achieve a desired spending level, rather than historic or recent inspections showing higher and increasing failures, damaged, and defective equipment.

The Company failed to address Mr. Ozar's testimony calling for a higher showing cost effectiveness and reliability benefits at the circuit level to justify substantial spending increases.[242] The Company has not evaluated the effectiveness of "line modernization" to justify the increasing

[239] Ozar Direct, 8 TR 3997.

[240] Pfeuffer Rebuttal, 4 TR 432.

[241] Ozar Direct, 8 TR 3961-65.

[242] *Id.* at 3997.

program cost.[243] Company data shows a small fraction of outages are attributable to equipment (9% of customer-minute interruptions and 23% of events), but pole equipment constitutes only about one-third of those events.[244] The Commission should adopt Mr. Ozar's recommendation and require the Company to assess cost and reliability benefits of the Pole/PTMM program to support increasing spending in this program in future cases.

4. Conclusion to this section.

The Commission should adopt Mr. Ozar's recommendation and reject the Company's request to increase spending in the Pole/PTMM program. The Company has failed to demonstrate that spending above the 2021 level is reasonable and prudent. The Company also should refocus the program to avoid costly "modernization" or replacement, absent a showing of imminent failure or demonstrated increasing risk of failure. Moreover, the Company should continue and even increase its pole inspection cycle to a 5-year cycle, which is likely to lead to preemptive repairs that avoid capital replacements, thus lowering costs for ratepayers.

IV. COST OF CAPITAL

A. Return on Equity [245]

1. Introduction to this section

DTE Electric witness Dr. Bente Villadsen testified in support of modification to the authorized return on equity (ROE) approved in DTE Electric's last rate case from 9.9% to

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[243] Ozar Direct, 8 TR 3997.

[244] Ex MEC-19; Ozar Direct, 8 TR 3980, 3995.

[245] MNSC believes the following constitutes the record on this topic:

- Villadsen Direct, 7 TR 1303-94;
- Villadsen Rebuttal, 7 TR 1395-1445;
- Ex A-14, Sch D5.1 to Sch D5.8;

10.25%.[246] Witnesses on behalf of Staff, the Attorney General, ABATE, and MEC-CUB testified in opposition to the Dr. Villadsen's recommendation and submitted their own cost of equity analyses. Each of these analyses supported downward modifications from the current 9.9% rate set in U-20561. MNSC acknowledges that Mr. Garrett's recommended ROE at 8.8% is at the bottom of the range of ROE's proposed by Staff and intervening witnesses in this case. MNSC maintains that Mr. Garrett accurately calculated DTE's market-based cost of equity. He further presents a compelling argument for the Commission to apply a higher level of scrutiny to align awarded ROE with market-based cost of equity. In any event, with or without Mr. Garrett's analysis, the weight of the evidence strongly supports a reduction in DTE's currently-approved cost of equity.

2. MEC-CUB supports a move to realign awarded ROE with market-cost of equity.

On behalf of MNSC, David Garrett testified that the Commission should reject the Company's proposed increase in ROE to 10.25% because it is excessive and unsupported.[247]

- Ex A-47, Sch LL1 and Sch LL2;
- Ufolla Direct, 8 TR 5080-5101;
- Exs S-4, Sch. D-1 to Sch D-5;
- Ex S-13;
- Coppola Direct, 8 TR 4817-46;
- Ex AG-1.27, 1.28, 1.32, 1.33, 1.35
- Walters Direct, 8 TR 3045-3115;
- Exs AB-11 to AB-27
- Dauphinais Direct, 8 TR 2903-2906;
- Garrett Direct, 8 TR 3866-3951;
- Exs MEC-36 to MEC-52;
- Exs MEC-122C, MEC-123C, MEC-124C, MEC-125C;
- Koeppel Direct, 8 TR 4329-42.

[246] Villadsen Direct, 7 TR 1355-56.

[247] Garrett Direct, 8 TR 3868-69.

Instead, Mr. Garrett supported an awarded ROE of 8.8%, which is still in excess of the DTE's cost of equity (7.4%) because it is a gradual but meaningful move towards market-based cost of equity.

Mr. Garrett provided an overview of the meaning and significance of Cost of Capital, of which cost of equity is one component (along cost of debt and capital structure), and one that is not explicitly quantifiable.[248] Courts that have weighed in on ROE have clearly established that awarded ROE must be just and reasonable, but it need not be set exactly to equal to cost of equity.[249] Mr. Garrett testified that awarding an ROE that is too far above the utility's cost of equity, which he calculated to be 7.4%, is at risk of violating the legal standards for awarded ROE.[250] This is because awarding an ROE substantially in excess of the true cost of capital results in an improper transfer of wealth from ratepayers to shareholders.[251] Mr. Garrett testified that the trend in excess awarded ROEs relative to utility cost of equity has negative economic impacts, and ultimately leads to customers paying higher rates without receiving corresponding benefits.[252] Mr. Garrett supported moving towards awarded ROE that more closely reflects market-cost of capital, guided to by two key legal principles:[253]

1. **<u>Risk is the most important factor in determining awarded return</u>**. The awarded return in this case should reflect DTE's relatively low market risk. Mr. Garrett explained that utilities are "defensive firms" that have low betas and they are comparatively unaffected

[248] *Id.* at 3870-71.

[249] *Id.* at 3875-79.

[250] *Id.* at 3879-82.

[251] *Id.* at 3877, 3880.

[252] *Id.* at 3881-82 (citing Charles S. Griffey, "When 'What Goes Up' Does Not Come Down: Recent Trends in Utility Returns," White Paper (February 2017)).

[253] *Id.* at 3882-83.

by overall market conditions, which means shareholders are assured stock prices that do not fluctuate wildly, and awarded return should also reflect that market insulation.[254]

2. **<u>The awarded return should be sufficient to assure financial soundness and integrity under efficient management</u>**. The trend of awarded return in excess of market costs supports financial soundness even under relatively inefficient management, but the regulatory should strive to promote efficiency and minimize economic waste by aligning awarded ROE with market cost of equity.[255]

Building on this foundation, Mr. Garrett used two models to estimate DTE's market cost of equity. To do so, Mr. Garrett used the same proxy group of electric utilities that Dr. Villadsen used; like many other witnesses, he rejected the inclusion of non-electric companies in the proxy group.[256] *<u>First</u>*, he evaluated DTE's cost of equity using the DCF model, with particular emphasis on the appropriate growth rate factor.[257] Mr. Garrett fully supported his inputs and addressed the flaws in Dr. Villadsen's application of the DCF model. Mr. Garrett's analysis concluded that DTE's cost of equity is 7.1% under the DCF model.

<u>Second</u>, Mr. Garrett evaluated DTE's cost of equity using the CAPM model.[258] In his assessment, Mr. Garrett addressed the flaws in Dr. Villadsen's application of the model, including her flawed "financial risk adjustment."[259] Mr. Garrett's application of the CAPM model estimated that DTE's cost of equity is 7.7%.

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[254] *Id.*, 3886-93.

[255] *Id.* at 3883.

[256] *Id.* at 3884-85.

[257] *Id.* at 3893-3911.

[258] *Id.* at 3911-28.

[259] *Id.* at

Third, Mr. Garrett addressed Dr. Villadsen's application of the risk premium model to assess DTE's cost of equity.[260] Principally, the risk premium model is not only flawed because it is a backwards instead of forwards looking, but it is redundant of the CAPM model that is effectively a "risk premium" model.

Using the average of the two models, the estimated market cost of equity for DTE of about 7.4%. Mr. Garrett recommended the Commission award DTE an ROE of 8.8% (the midway point between DTE's current 9.9% ROE and the higher 7.7% CAPM market cost of equity), which is still well above the market cost of equity.[261]

In rebuttal testimony, Dr. Villadsen addressed a variety of issues and maintained that 10.25% is the appropriate awarded ROE for DTE.[262] MNSC address the Company's rebuttal on the three primary issues that support Mr. Garrett's testimony and the need for the Commission in this case to award an ROE that better aligns with market cost of equity. In particular, this brief addresses Dr. Villadsen's criticisms of the growth rate factor in the DCF model, the market risk premium in the CAPM, the duplicative risk-premium adjustment for low-beta stocks in the ECAPM, and Dr. Villadsen's "financial leverage" adjustment to market-cost of equity.

3. Dr. Villadsen's growth rate in the DCF model is flawed and unreliable.

Dr. Villadsen asserts that Mr. Garrett's lowest ROE estimate is the result of applying for growth rate the nominal GDP growth estimate, instead of analysts' forecasts, suggesting that he "departs from that accepted approach."[263] More particularly, Dr. Villadsen claims Mr. Garrett misunderstands the growth rate in Dr. Villadsen's DCF analysis, that Mr. Garrett's use of a long-

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[260] *Id.* at 3931-32.

[261] *Id.* at 3898.

[262] Villadsen Rebuttal, 7 TR 1403-45.

[263] *Id.* at 1406.

term GDP growth rate from 2021 is "meaningless," and that it is appropriate and "not controversial" to instead rely on analysts' forecasts for the growth rate in the DCF model.[264] The sections that follow explain why it is appropriate to incorporate the long-term GDP growth rate, and inappropriate to rely heavily on analysts' forecasts of growth rate in the DCF model. They also address the assertion that Mr. Garrett did not understand Dr. Villadsen's growth rate.

a. <u>It is appropriate to use the long-term GDP for growth rate in the DCF analysis.</u>

Dr. Villadsen asserts that it is "meaningless" to use long-term GDP from 2021 as suitable growth rate for electric utilities.[265] According to Dr. Villadsen, the use of long-term GDP fails to take into consideration the unique features of the industry, and it results in a 2% downward bias in Mr. Garrett's DCF estimate. Dr. Villadsen's testimony and her DCF modeling is incompatible with the stable growth DCF model because Dr. Villadsen improperly incorporates short-term growth using analysts forecasts to extrapolate long-term growth.

Mr. Garrett fully explained why it is appropriate and reasonable to use GDP for long-term growth rate in the DCF model for a stable utility like DTE Electric. Mr. Garrett used the Quarterly Approximation DCF Model, meaning the model assumes cash flows in the forms of dividends compound quarterly at a constant rate forever.[266] The use of a constant (or stable or terminal) growth rate (as opposed to a multi-stage model) is appropriate for a mature, low-growth utility like DTE, whereas a multi-stage growth rate may be more appropriate for young, high-growth firms where there long-term (terminal) growth rate is less transparent.[267] It is unnecessary to apply the multi-stage approach to estimate the value of a firm that is expected to go through various stages

[264] *Id.* at 1413, 1415-17.

[265] *Id.* at 1413.

[266] Garrett Direct, 8 TR 3893, 3896-97.

[267] *Id.* at 3897.

of growth before reaching the final or "terminal" growth stage.[268] This is because regulated utilities are already in their terminal or low growth stage. They are constrained by physical service territories, and they are limited by ratepayer and load growth within that territory.

Mr. Garrett explained the fundamental point that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates, and so the terminal growth rate in the DCF model should not exceed the aggregate economic growth rate.[269] A regulated utility may in fact grow at a rate lower than the U.S. economic growth rate. For mature companies in mature industries, it is reasonable to expect a terminal growth rate between inflation and nominal GDP.

Dr. Villadsen cited testimony by ABATE witness Walters to support her criticism of Mr. Garrett's use of nominal GDP for long-term growth in the constant DCF model.[270] This criticism is misplaced. Mr. Walter's cited authority for the proposition that it is appropriate to use the constant growth model, with nominal GDP, "for mature companies with a stable history of growth and stable future expectations."[271] Mr. Walters explained that utilities cannot indefinitely sustain a growth rate that exceeds the economy where they sell services when utility earnings and growth are created by increased rate base investments, and he cited EIA data showing that utility sales growth tracks U.S. GDP growth, at a lower level.[272] Mr. Walters concluded:

> Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. Therefore,

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[268] *Id.* at 3900.

[269] *Id.*at 3902.

[270] Villadsen Rebuttal, 7 TR 1415-16.

[271] Walters Direct, 8 TR 3057 (quoting *Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298).

[272] *Id.* at 3075; Ex AB-18.

> the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.[273]

Mr. Walters impugned the use of analysts' forecasts for long-term growth for DTE the same reasons Mr. Garrett did.

DTE Electric is fundamentally different than competitive firms that are not regulated monopolies with fixed service territories. Competitive firms may increase growth by launching a new product line, franchising, or expanding into new markets.[274] Regulated utilities cannot do those things. As discussed below, Dr. Villadsen applied the stable growth DCF model using analyst forecasts of growth, which is not a reasonable assessment of long-term growth for a mature stable utility like DTE.

b. <u>Analysts' growth rate forecasts are not a reliable estimate of long-term growth for DTE.</u>

Mr. Garrett did not rely on analysts' forecasts of growth because that determinant is a better indication of short- to mid-term growth for firms with average to high growth opportunities, not stable mature companies like DTE.[275] He further testified regarding the limitations of analysts' growth rates in the context of regulated utilities.[276] While competitive firms may have strategies and opportunities to achieve real, sustained earnings growth, regulated utilities cannot engage in the same potential growth opportunities. The two factors that contribute to utility growth are rate base and awarded ROE. In awarding ROE, if analysts' projections are given undue weight, this creates the potential for a feedback loop: if a regulator awards an ROE that is above the market-based cost of capital, this could lead to higher short-term growth rate projections from analysis, and when short-term growth rates are used in the DCF Model, it could lead to higher awarded

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[273] *Id.*

[274] Garret Direct, 8 TR 3902.

[275] *Id.* at 3899.

[276] *Id.* at 3904-07.

ROEs.[277] Mr. Garrett cautioned against the reliance on quantitative growth projections published by analysts because this will not necessarily provide fair indications of real, sustainable utility growth. Finally, Mr. Garrett noted the obvious and indisputable fact that institutional analysts' estimated projections are short-term assessments, not long-term projections, and it is inappropriate to use them as if they are long-term projections.[278] For the reasons discussed in the preceding section, the stable growth DCF model that Mr. Garrett applied appropriately applied long-term growth rates, which are constrained by long-term economic factors.

In response to Mr. Garrett's testimony explaining the impropriety of using analysts' forecasts of growth in a DCF model to estimate cost of equity for DTE, Dr. Villadsen argued in support of analysts' forecasts of growth rates.[279] Dr. Villadsen relies on a selective recitation of sources to support her position. Returned to their full context, the sources do not support Dr. Villadsen's approach nor her criticism of Mr. Garrett's long-term growth factor.

First, Dr. Villadsen asserts that "most cost of capital guides suggest using analysists' forecasts to proxy for growth in cost of equity calculations, citing *Brealey, Meyers and Allen,* Principles of Corporate Finance.[280] The one cited resource states that utilities and regulators have noticed that "[[[redacted]]]."[281] The authors note that analysts forecasts are one option to estimate growth rates, but cautions these forecasts do not typically extend beyond five years because "[[[redacted]

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[277] *Id.* at 3905-06.

[278] *Id.* at 3906-07.

[279] Villadsen Rebuttal, 7 TR 1414-17.

[280] *Id.* at 1415, n. 33; see Ex MEC-122C (except of cited textbook).

[281] Ex MEC-122, p. 3.

[redacted]]]."[282] The authors provide other options to estimate growth, and later in addressing the constant-growth DCF model, the authors caution:

> [[redacted]]].[283]

This resource does not contradict Mr. Garrett's approach and concerns regarding analysts' forecasts.

Second, Dr. Villadsen asserts that ABATE witness Walters used analysts' forecasted earnings per share growth rates.[284] Dr. Villadsen emphasizes Mr. Walters' testimony that "securities analysists' growth estimates have been shown to be more accurate than growth rates derived from historical data."[285] Indeed, Mr. Walters provided a constant growth DCF analysis using a consensus (average) of analysts' growth forecasts for the proxy companies of 5.61% and a mean growth rate also based on the analysts forecasts of 5.93%.[286] However, on the next page of his testimony, Mr. Walters explained why a growth rate based on analysts' forecasts is unsustainable because it is 40% higher than long-term projected GDP.[287] Mr. Walters continues by noting that a long-term sustainable growth rate for a utility stock "cannot exceed the growth rate of the economy in which it sells its goods and services." For this reason, Mr. Walters testified that the long-term maximum sustainable growth rate for a utility investment is "best proxied by the projected long-term GDP growth rate as that reflects the projected long-term growth rate of the

[282] *Id.*

[283] *Id.* at p. 4.

[284] *Id.* at 1415.

[285] *Id.*, quoting Walters Direct, 8 TR 3069-70.

[286] Walters Direct, 8 TR 3070.

[287] *Id.* at 3071.

economy as a whole." Later in his testimony, Mr. Walters provided academic and investment practitioner support for using the projected long-term GDP growth outlook as a maximum long-term growth rate projection. Mr. Walters testimony supporting the use of the long-term GDP as a proxy for growth in the DCF model also supports Mr. Garrett's approach.

Third, Dr. Villadsen supports her criticism of Mr. Garrett's long-term GDP growth rate, and bolsters her analysts' forecasts growth rate, by reference to an academic paper cited by Mr. Walters, which she claims documented the accuracy of analysts' growth rate forecasts over 30 years ago.[288] Mr. Walters supported his statement that "securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data" by reference to an paper published in 1989.[289] Dr. Villadsen mischaracterizes Mr. Walters' testimony and citation. Following the footnoted sentence, Mr. Walters clarifies that "analysts' growth projections are more likely to influence investors' decisions, which are observable in stock prices, than growth rates derived only from historical data."[290] This is different than saying academics have documented the accuracy of analysts' forecasts relative to historical data – Mr. Walters said investors are more influenced by analysts' growth projections than historic data growth rates, and he cited an article published in 1989 as support. Dr. Villadsen's rebuttal infers too much from this sentence.

Fourth, Dr. Villadsen claims that more recent papers have found that "efforts to curb analysts incentives to provide optimistic forecasts have worked and that issues pertaining to forecasts relate to firms with characteristics very different from those of utilities."[291] In support,

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[288] Villadsen Rebuttal, 7 TR 1416.

[289] *Id.* (referencing Walters Direct, 8 TR 3069, n. 13 (See, e.g., David Gordon, Myron Gordon, and Lawrence Gould, Choice Among Methods of Estimating Share Yield, The Journal of Portfolio Management, Spring 1989.).

[290] Walters Direct, 8 TR 3069-70 (emphasis added).

[291] Villadsen Rebuttal, 7 TR 1416.

Dr. Villadsen cites a 2010 paper by Hovakimina & Saenyasiri that found "the median forecast bias essentially disappeared."[292] What is glossed over between Dr. Villadsen's discussion about the paper Mr. Walter cited and the paper she cited is the body of literature documenting the problem of analysts' optimism bias – the documented concern that analysts tend to bias towards inflated earnings forecasts because it gains privileged information and due to potential conflicts of interest.[293] The 2010 Hovakimina & Saenyasiri paper is of little value here. [[[redacted]]][294] This study is not a basis to conclude that analyst bias disappeared in the context of utilities.

Fifth, Dr. Villadsen cited three studies for the proposition that analysts are too optimistic about stocks for difficult-to-value firms – *i.e.*, volatile companies.[295] She then concluded that "optimism bias is not expected to be an issue for utilities."[296] This is an illogical conclusion. That optimism bias is prevalent for volatile companies does not mean it is non-existent for stable utilities.

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[292] *Id.* citing A. Hovakimina & E. Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts Journal,* vol. 66, 2010 (excepted in Ex MEC-123C).

[293] Ex MEC-123C, p. 1 of 13.

[294] *Id,* pp. 8-10.

[295] Villadsen Rebuttal, 7 TR 1416 (citing Hribar & McInnis (2012), Scherbina (2004), and Michel & Pandes (2012).

[296] Villadsen Rebuttal, 7 TR 1417.

Dr. Villadsen did not demonstrate the use of analysts' forecasts is an appropriate proxy for long-term sustainable growth rate for DTE, and Mr. Garrett's use of long-term GDP is reasonable.

c. Mr. Garrett understood the growth rate Dr. Villadsen applied.

A final comment regarding Dr. Villadsen's rebuttal testimony is warranted. She asserts that Mr. Garrett "misconstrued" her DCF analysis long-term growth rate – she used an average rate of 5.5%, but she claims Mr. Garrett incorrectly presents the growth rate for one company (NextEra Energy) alone.[297] Mr. Garrett neither misconstrued nor inaccurately presented Dr. Villadsen's approach. Mr. Garrett noted that Dr. Villadsen assumes projected long-term growth rates "as high as 8.3% in her DCF model" and that she "uses a "long-term" growth rate estimate of 8.3% for NextEra Energy."[298] He goes on to explain that this projection that NextEra will grow at 8.3% per year for decades to come, well beyond the short-term that the analyst projected, is unrealistic and contrary to the fundamental concept of long-term growth. Mr. Garrett did not misunderstand that Dr. Villadsen included NextEra among 45 other utility growth rates in her DCF assessment;[299] he reasonably illustrated what it means to rely on these analyst projections in the context of the constant DCF model.

4. Dr. Villadsen's CAPM results are unreliable, and her ECAPM method should not be given any weight.

Dr. Villadsen also used the Capital Asset Pricing Model, or CAPM, and a variation of that model that she calls the Empirical Capital Asset Pricing Model, or ECAPM. The CAPM states that the cost of capital is equal to the risk-free rate plus a risk premium.[300] The risk premium is equal to the market risk premium (sometimes called the equity risk premium) multiplied by a beta

[297] *Id.* at 1415.

[298] Garrett Direct, 8 TR 3910.

[299] Ex A-14, Sch D5.5.

[300] Villadsen Direct, 7 TR 1343; Garrett Direct, 8 TR 3911-12.

coefficient.[301] The risk-free rate is the level of return that investors can achieve without assuming any risk, and is typically represented by the yield on long-term U.S. Treasury bonds.[302] The market risk premium represents the level of risk that investors expect above the risk-free rate for investing in securities that carry risk.[303] Beta represents the sensitivity of a given security to movements in the market.[304] The ECAPM adjusts the CAPM result using an alpha coefficient, which has the effect of increasing the risk premium of low-beta stocks like regulated electric utilities.[305]

After applying a "financial leverage adjustment" discussed in the next section, Dr. Villadsen's CAPM and ECAPM results ranged from 10.3% to 11.4%, depending on which of two market risk premium scenarios she assumed.[306] By contrast, the CAPM results from Staff and Intervenor witnesses were:

[301] *Id*.

[302] Garrett Direct, 8 TR 3912.

[303] *Id*. at 3914.

[304] *Id*. at 3913.

[305] Villadsen Direct, 7 TR 1343-44.

[306] Villadsen Direct, 7 TR 1346.

Party	Witness	CAPM result
MEC/CUB	David Garrett	7.7%.[307]
Attorney General	Sebastian Coppola	9.39%.[308]
ABATE	Christopher Walters	9.6%.[309]
Staff	Joseph Ufolla	9.08% historic.[310] 10.69% projected.[311] Average = 9.885%.
Staff / Intervenor Average	**9.14%**	
Staff / Intervenor Median	**9.495%**	

The Staff and Intervenor witnesses did not produce results using the ECAPM method.

Dr. Villadsen's CAPM results should be rejected for two reasons: because her Scenario 2 market risk premium is inflated and because her financial leverage adjustment should be rejected. The financial leverage issue is addressed in Section 5, below. As to Dr. Villadsen's ECAPM results, those should be rejected because ECAPM is not a valid method to establish a utility's cost of equity in a rate case, and the MPSC has rejected its use for that purpose in the past.

<u>L4 - CAPM</u>

In Table 2 of her rebuttal testimony, Dr. Villadsen summarized some of the assumptions used by Staff, Intervenors, and her in the models.[312] Then she criticized Staff and Intervenor assumptions for the CAPM in the pages following Table 2 and again in Section II.C.2; and

[307] Garrett Direct, 8 TR 3920-21.

[308] Coppola Direct, 8 TR 4832.

[309] Walters Direct, 8 TR 3093.

[310] Ufolla Direct, 8 TR 5094.

[311] *Id*. at 5095.

[312] Villadsen Rebuttal, 7 TR 1405.

responded to Intervenor criticisms of her assumptions in Section II.D.2. These discussions are consolidated by assumption type for purposes of efficiency.

L5 – Risk-free rate.

Villadsen assumed a risk-free rate of 2.73%. She noted in her direct testimony that yields on U.S. Government bonds were depressed in January due to monetary policies.[313] However, looking forward, she predicted that treasury bonds were forecasted to increase.[314] She stated that Blue Chip Economic Indicators' October 2021 edition projected that the yield on 10-year treasury bonds will increase, and be 1.9% in 2022, 2.3% in 2023, and 2.5% in 2024.[315]

MNSC witness Garrett assumed a risk-free rate of 2.74%. He derived this rate from a 30-day average of daily yield curve rates on 30-year Treasury bonds.[316] Staff witness Ufolla assumed a risk-free rate of 2.823%. He derived his assumption from IHS Markit projections over a three-month period of 30-year Treasury bond yields in 2023.[317]

On rebuttal, DTE witness Villadsen argued that the risk-free rates used by Mr. Garrett and Mr. Ufolla are too low. She argues that instead of using an average of risk-free rates over 30 days leading up to May 2, 2022, Mr. Garrett should have used the May 2, 2022 forecast, which was 3.07%.[318] Similarly, Dr. Villadsen argued that Staff witness Ufolla's risk free rate is too low because he should have used the most recent available forecast instead of an average of risk-free rates over three months.[319] However, Mr. Garrett's risk-free rate is one basis point higher than Dr.

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[313] Villadsen Direct, 7 TR 1320.

[314] *Id.* at 1321-22.

[315] *Id*.

[316] Garrett Direct, 8 TR 3912-13; Ex MEC-42.

[317] Ufolla Direct, 8 TR 5093.

[318] Villadsen Rebuttal, 7 TR 1405.

[319] *Id*. at 1405-06.

Villadsen's, and Mr. Ufolla's risk-free rate is a little over nine basis points higher. As noted above, Dr. Villadsen anticipated in her direct testimony that yields were depressed in January and would be increasing quickly. If thereafter she determined that risk-free rates had changed so quickly and to such an extent that it made her initially-assumed increase inaccurate, she could have filed supplemental testimony to update her assumption. It is not fair to expect other parties to respond to a moving target. Further, Dr. Villadsen offers no testimony to support her position that using a single forecast is more reliable than using an average over a reasonable period of time.

ABATE witness Christopher Walters assumed a risk-free rate of 3.30% for his CAPM analysis;[320] and Attorney General witness Sebastian Coppola assumed a risk-free rate of 3.20%.[321] Dr. Villadsen did not challenge either of those assumptions in her rebuttal.

[320] Walters Direct, 8 TR 3085.

[321] Coppola Direct, 8 TR 4831-32.

L5 – Beta

The parties assume the following beta coefficients:

Party	Witness	Beta
DTE	Villadsen	0.91[322]
MEC/CUB	Garrett	0.87[323]
Attorney General	Coppola	0.85[324]
ABATE	Walters	range of betas[325]
Staff	Ufolla	0.86.[326]
Staff/AG/MEC-CUB Average		**0.86**
Staff/AG/MEC-CUB Median		**0.86**

Dr. Villadsen does not directly challenge the Staff and Intervenor betas in her rebuttal, but rather focuses on her financial leverage adjustment and on or the application of the ECAPM. Those issues are addressed further below.

[322] Villadsen Direct, 7 TR 1309, fn 7.

[323] Garrett Direct, 8 TR 3920-21.

[324] Coppola Direct, 8 TR 4833.

[325] Walters Direct, 8 TR 3093.

[326] Ufolla Direct, 8 TR 5093.

L5 – Market or Equity Risk Premium

The parties assume the following market risk premiums:

Party	Witness	MRP	Source
DTE	Villadsen[327]	Scenario 1: 7.25% Scenario 2: 7.89%	Scenario 1: historic average Scenario 2: Bloomberg October 2021
MEC/CUB	Garrett[328]	5.50%	IESE Business School Survey and Duff & Phelps Report
ABATE	Walters	(1) 5.50% (2) 8.74%	DCF method benchmarked against Kroll rate.[329] Long-term market return plus inflation minus the risk-free rate.[330]
Attorney General	Coppola	7.25%	Long term historic average.[331]
Staff	Ufolla	7.25%	Long-term historic average.[332]
Staff-Intervenor Average		**6.78%**	
Staff-Intervenor Median		**7.185%**	

In rebuttal, Dr. Villadsen argues that MNSC witness Garrett used the lowest market risk premium of any of the other parties.[333] However, that is because Mr. Garrett did not rely on historic averages and the other parties did. Mr. Garrett explained in his direct testimony that empirical research has shown that future MRPs are lower than historic average MRPs.[334] Dr. Villadsen did

[327] Villadsen Direct, 7 TR 1326-27.

[328] Garrett Direct, 7 TR 3920 and Exhibits MEC-45 and MEC-46.

[329] Walters Direct, 8 TR 3088-92.

[330] Walters Direct, 8 TR 3098. The average of Mr. Walters' two MRPs is 7.12%.

[331] Coppola Direct, 8 TR 4832-33.

[332] Ufolla Direct, 8 TR 5093.

[333] Villadsen Rebuttal, 7 TR 1406.

[334] Garrett Direct, 7 TR 3915-16.

not respond to this point directly. Further, the MRP derived by ABATE witness Walters from the DCF method reached the same result as Mr. Garrett's assumption.

As to witness Villadsen's assumed MRP of 7.89%, Attorney General witness Coppola testified that this number is 64 basis points higher than the historical average from 1926 to 2020.[335] He noted that Dr. Villadsen used a projected beta she obtained around the time she prepared her testimony. That projection reflected "circumstances in the market at a very short point in time which have now changed due to higher interest rates and lower stock prices."[336]

<u>L4 – ECAPM</u>

As noted earlier, Dr. Villadsen also presented results using the ECAPM analysis. She explained that the ECAPM adds an alpha coefficient to the CAPM formula to account for empirical research that she says shows "that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta."[337] As applied in this case, the ECAPM produced only minor differences from the CAPM because the betas of the proxy group were already closer to 1.0 than in past cases.[338] Even so, several parties criticized Dr. Villadsen's application of the ECAPM. The main reason was because the beta values she used as inputs were not raw beta values as described in the literature describing the ECAPM. Rather, the betas provided by services such as Value Line or Bloomberg are already adjusted to account for the empirical observation Dr. Villadsen describes.[339] Applying the ECAPM to these adjusted betas results in their being adjusted twice.

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[335] Coppola Direct, 8 TR 4833.

[336] *Id*.

[337] Villadsen Direct, 7 TR 1343.

[338] Ufolla Direct, 8 TR 5097.

[339] Ufolla Direct, 8 TR 5097; Walters Direct, 8 TR 3108; Garrett Direct, 8 TR 3928.

Staff also noted that the Commission has not historically relied on ECAPM analyses in rate cases.[340] In Case No. U-20561, the ALJ found that the alpha values in DTE witness Villadsen's ECAPM analysis duplicated the adjustments to the betas provided by Value Line that she used in her CAPM analysis.[341] The Commission noted the ALJ's criticism of the ECAPM on this basis.[342] Two other recent PFDs in electric rate cases have also been critical of the use of adjusted betas used in the ECAPM analysis.[343] In her rebuttal testimony, Dr. Villadsen insists that the adjustment to the betas provided for the CAPM and the adjustment via the alpha coefficient are separate.[344] However, she does not explain how her method in this case differs from the method rejected in U-20561, or the methods criticized in U-18255 and U-17735.

For all of these reasons, the CAPM and ECAPM results offered by witness Villadsen should not be adopted for the purpose of calculating DTE's cost of equity, and the average or median of the Staff and Intervenor CAPM analyses should be adopted instead.

5. **Dr. Villadsen's financial leverage adjustment is unreasonable and should again be rejected.**

Dr. Villadsen applied a "financial risk adjustment" to the results of her DCF and CAPM models "so the results reflect the value of the capital that investors hold during the estimation period."[345] Mr. Garrett opposed this approach because regulated utilities are not more risky than market average (beta greater than 1.0).[346] The average beta of the proxy group is 0.9, reflecting

[340] Ufolla Direct, 8 TR 5097.

[341] Case No. U-20561, March 5, 2020, PFD, pp. 301-302.

[342] Case No. U-20561, May 8, 2020, Order, p. 173.

[343] Case No. U-18255, January 26, 2018, PFD, p. 134; Case No. U-17735, September 16, 2015, PFD, p. 86.

[344] Villadsen Rebuttal, 7 TR 1421-22.

[345] Villadsen Direct, 7 TR 1342.

[346] Garrett Direct, 8 TR 3924.

this relatively low risk. While the concept that different capital structure ratios can impact both cost of equity and cost of debt, applying the Hamada formula the way Dr. Villadsen did – to unlever and relever ROE according to capital structure – is inappropriate and out of context.[347] The other intervener witnesses who addressed ROE also took issue with Dr. Villadsen's financial risk adjustment.[348]

In rebuttal, Dr. Villadsen significantly expounds on the financial leverage adjustment.[349] MNSC respond to make three additional points related to this proposal for awarding ROE.

First, ALJs and the Commission have uniformly and appropriately rejected this approach numerous times, and should do so again. These cases include:

- Case No. U-18014, Nov. 21, 2016, PFD, pp. 180-190 ("This PFD recommends that the Commission give no weight to the ATWACC calculations presented by Dr. Vilbert."); Jan. 31, 2017, Order, p. 66 ("the Commission does agree with the PFD that little or no weight should be given to the utility's ATWACC calculations");
- Case No. U-18255, Jan. 26, 2018, PFD, p. 135 ("Among other problems, this methodology is overly complex and unjustifiably increases ROEs at the expense of rate payers and to the benefit of utility investors."); April 18, 2018, Order, pp. 32 ("The Commission agrees with the PFD that little weight should be given to the utility's ATWACC calculations.");
- Case No. U-20162, March 6, 2019, PFD, p. 124; May 2, 2019, Order, pp. 66-67; and
- Case No. U-20561, March 5, 2020, PFD, pp. 292-95, 301-303 ("the Commission has already rejected the ATWAAC method of adjusting proxy group results, and DTE has not

[347] *Id.* at 3924-27.

[348] Garrett Direct, 8 TR 3924; Ufolla, 8 TR 5091-93, 5096; Coppola, 8 TR 4828-29; Walters, 8 TR 3101-59.

[349] Villadsen Rebuttal, 7 TR 1429-45.

presented new or persuasive evidence that the Commission's decision was erroneous;"); May 8, 2020, Order, p. 176.

Second, contrary to her testimony, Dr. Villadsen's approach is not "exactly as described in standard textbooks … and the CFA curriculum."[350] The confidential textbooks and CFA curriculum cited in note 94 describe ATWACC to compare cost of capital between two companies that may be differently leveraged and taxed, but none propose that a regulator should apply an ATWACC "financial leverage adjustment" to increase the modeled DCF/CAPM estimated ROE in setting the rewarded ROE for a regulated utility.[351]

Third, Dr. Villadsen identified a series of regulatory decisions that she characterizes as adopting a similar approach. However, it is unclear that these decisions do what Dr. Villadsen proposes to do: unlever and relever estimated ROE to reflect the average after tax weighted cost of average adjustment for the proxy group by the regulator in a rate case awarding ROE. Dr. Villadsen indicates that FCC, FERC, and STB calculated the average weighted cost of capital in various ways, but not that they applied an ATWACC adjustment to increase awarded ROE beyond the DCF/CAPM results. Notably, the quoted Alabama PSC case states the ATWACC "analysis" is not prevalent but is "compelling" – it is unclear if the analysis is the same as Dr. Villadsen's complex approach or different, and also whether the Alabama PSC applied the ATWACC leverage in awarding ROE. It is unhelpful that the California PUC relies on results from "the method," the Oregon PUC "relies on a version of the Hamada method," the Florida PUC "used an equivalent methodology" and international regulators "rely on a mixture of [ATWACC] and the Hamada method."[352] Given the complexity Dr. Villadsen's proposed methodology, as recognized by prior

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[350] *Id.* at 1440.

[351] Ex MEC-124C (textbook excerpts), Ex MEC-125C (CFA curriculum).

[352] *Id.* at 1442-43.

ALJs and the Michigan PSC, this vague testimony is insufficient basis to conclude that these other regulators applied this novel method in precisely the same novel and complex way DTE proposes in this case. Although Dr. Villadsen suggests these other regulators' adoptions are "relatively new" and concludes these jurisdictions have "moved towards accepting the importance of the leverage," all of the cited decisions date from 2012 to 2019.[353] Even if there were evidence of recent trend (which MNSC disputes), these decisions all predate the consistent and recent Michigan PSC decisions that have rejected the ATWACC adjustment methodology.

6. Conclusion to this subsection.

The Commission should reject the Company's recommendation to increase the awarded ROE. Mr. Garrett provided a comprehensive and sound analysis showing the Company's market-based cost of equity is up to 7.7%. He also testified to the importance and legal necessity of awarding an ROE that is not substantially above the market-based cost of equity. When awarded ROE substantially exceeds reasonable estimates of the regulated utility's market-based cost of equity, the result is an unfair transfer of wealth from ratepayers to shareholder, and is inconsistent with the legal standards for ROE.

B. Capital Structure[354]

DTE Electric witness Lepczyk recommended a projected capital structure of 50% long-term debt and 50% common equity. Mr. Garrett addressed the relative importance of capital

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[353] *Id.,* notes 95-104.

[354] MNSC believe the record on this issues consists of the following:

- Lepczyk Direct, 7 TR 1283-95;
- Ex A-1, Sch. A2;
- Ex A-4, Sch. D2 to D5;
- Ex A-14, Sch. D1.1, D2 to D4;
- Ex A-18, Sch H1 and H2;
- Lepczyk Rebuttal, 7 TR 1297-99;

structure in the context of regulated utility.[355] There is opportunity for competitive firms to maximize value by finding an efficient balance between debt and equity ratios, beyond which the benefits of increasing debt do not outweigh the cost of additional risk to shareholders.[356] However, regulated utilities lack the incentive to minimize their WACC because under the base rate of return model, a higher WACC results in higher rates, all else held constant.[357] In addition, utilities can afford a capital structure with a higher debt ratio because they are generally low risk, with stable earnings and fixed assets.[358] Without shareholders insisting the utility minimize its overall cost of capital, the regulator is the substitute and should set rates accordingly.[359] Mr. Garrett proposed that the Commission consider imposing a higher debt ratio for DTE Electric, consistent with the proxy companies and other well-established industries, including public utilities, suggesting a debt rate of 53%.[360]

Mr. Lepczyk opposed the recommendation to alter the debt ratio, noting that DTE's proposed 50% debt is in line with peer operating utilities, which is more relevant than their respective holding company's debt ratios.[361] Without conceding the Company's rebuttal position, MNSC accepts for this case maintaining the Company's proposed 50% permanent debt ratio for now. However, the record clearly shows that DTE's proposed 50% debt ratio and also the proxy

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- Ufolla Direct, 8 TR 5083-5084;
- Garrett Direct, 8 TR 3932-42; and
- Ex MEC-49, MEC-50.

[355] Garrett Direct, 3932-42.

[356] *Id.* at 3933-34.

[357] *Id.* at 3935.

[358] *Id.* at 3936.

[359] *Id.* at 3937.

[360] *Id.* at 3938-42.

[361] Lepczyk Rebuttal, 1297-98.

group operating utility average debt ratio (47.4%) are relatively low compared to the proxy group holding companies (53%) and compared to industries like power companies (60%), wireless companies (59%), water utilities (57%), and green and renewable energy companies (56%).[362] This gap supports Mr. Garrett's testimony that there is an incentive or value for competitive firms (including the holding companies and industries) to increase debt ratio to the point that they maximize the WACC, which regulated utilities lack. One explanation for the low debt ratios of the proxy group operating companies is that regulators insufficiently substitute for competitive industries with shareholders who demand a lower overall cost of capital. Mr. Lepczyk did not address the foundation of Mr. Garrett's testimony that DTE's debt ratio should be set at a level that is sufficient to minimize the utility's overall cost of capital. The combined effect of a low debt ratio and an awarded ROE that well-exceeds the estimated market-based cost of capital for DTE appears to be unfair ratemaking. MNSC reserves these issues for a future proceeding.

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[362] Ex A-14, Sch. D1.1 (proxy group operating utilities); Ex MEC-49 (proxy group holding companies); Garrett Direct, 8 TR 3940, Fig. 14.

V. ADJUSTED NET OPERATING INCOME

A. Projected Tree Trim Expense[363]

The Company proposes to continue its investment in the Enhanced Tree Trim program (ETTP), supported by Witness Hartwick.[364] Two MNSC witnesses presented testimony related to the EPPT program.

Mr. Jester supported the Company's tree-trimming investment to improve reliability.[365] He discussed the role of trees in causing the Company's comparatively poor distribution system reliability indices (SAIDI, SAIFI, CAIDI), and the opportunity to improve those indices with a best practice trimming program. He noted the Company has failed to project the expected reliability benefits expected to result from the Company's tree trimming program alone.[366] He further noted that the Company should evaluate the cost-effectiveness of its other distribution system investments that are intended to provide reliability improvements to ensure balance between reliability and affordability for residential customers. Mr. Jester offered additional recommendations founded on the fac that tree trimming is an effective and cost-effective way to improve distribution reliability while also balancing important affordability considerations. His

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[363] This record regarding trimming consists of the following:

- Hartwick Direct, 7 TR 2277-2331;
- Hartwick Rebuttal, 7 TR 2332-34;
- Ex A-13, Sch C.5.6.1;
- Ex A-22;
- Ex A-31;
- Coppola Direct, 8 TR 4857-58,
- Jester Direct, 8 TR 3801-809;
- Ozar Direct, 8 TR 4030-4034; and
- Ex MEC-97.

[364] Harwick Direct, 7 TR 2277-31.

[365] Jester Direct, 3801-09.

[366] *Id.* at 3804.

specific recommendations that are founded in tree trimming effectiveness and cost-effectiveness are addressed below in the **Future Rate Cases, Further Study** section, related to distribution system planning modifications.

Mr. Ozar also addressed the Company's tree trimming program.[367] He likewise noted that tree trimming has proven to be one of the most effective means to enhance grid reliability and resilience. The reliability benefits of the trimming surge are documented in the Company's annual tree trim report.[368] Mr. Ozar specifically addressed the Company's program goal to achieve a uniform 5-year trim cycle. Recognizing the benefits of trimming generally, Mr. Ozar recommended continued innovation and improvement through the adoption of a pilot program that would shift from a -year uniform cycle to instead develop "unique cycle-lengths by bucket, based on tree intensity and other parameters."[369] This approach would prioritize high-density circuits with cycles less than 5 years. This more tailored approach to trimming could improve tree-related outages and drive even more economic reliability improvements for the distribution system.[370] Mr. Ozar provided additional details to explain and support his recommendation for a variable-cycle trimming pilot.[371] Mr. Ozar recommended that the Commission require the Company to initiate a pilot to test such an optimization approach for trimming based on circuit characteristics, and to file a report detailing the results, both in terms of reliability benefits and cost savings.[372]

No witness filed rebuttal testimony to the testimony from Mr. Jester and Mr. Ozar related to the Company's tree trim program and related expense. The Commission should adopt Mr.

[367] Ozar Direct, 8 TR 4030-34.

[368] Ex A-31 (2020 Tree Trim Annual Report); Ex MEC-97 (2021 Tree Trim Annual Report).

[369] Ozar Direct, 8 TR 4030.

[370] *Id.* at 4031.

[371] *Id.* at 4031-33.

[372] *Id.* at 4034.

Ozar's recommendation for the Company to pilot a variable cycle tree-trim program and report back the results, for the reasons discussed by Mr. Ozar.

VI. OTHER REVENUE RELATED ITEMS

A. Distribution Project Capitalization[373]

1. Introduction to this subsection

After his in-depth review of the Company's proposed capital spending in the 4.8kV hardening and the Pole/PTMM programs (discussed above), Mr. Ozar identified additional concerns related to the Company's approach to capitalization versus expensing in these two program areas.[374] After noting the regulatory incentive for a utility to capitalize, as opposed to expense, hardening and Pole/PTMM program costs,[375] he raised specific concern about the Company's capitalization of inspections,[376] and tree trimming in light of clear and contrary USOA guidance and other considerations.[377] Mr. Ozar raised further concerns about the Company's failure to explain the rationale supporting 80/20 split between installation/removal for capital inspections and trimming.[378] To address the concerns, Mr. Ozar recommended that the

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[373] The record regarding Distribution Project Capitalization consists of the following:

- Pfeuffer Direct, 4 TR 29-305;
- Uzenski Rebuttal, 7 TR 2789-92
- Ex A-12, Sch B5.4, p. 8, lines 9, 10 (Hardening, Pole/PTMM program capital expenditures);
- Becker Direct, 8 TR 5411-13;
- Ex S-5.15.3;
- Ozar Direct, 8 TR 3999-4016; and
- Exs MEC-20, 23, 24, 26, 28C, 29, 31, 32.

[374] Ozar Direct, 8 TR 3999.

[375] *Id.* at 3999-4003.

[376] *Id.* at 4003-05 (citing USOA Operating Expense Instruction 2 Maintenance A).

[377] *Id.* at 4005-12 (citing various USOA Accounts).

[378] *Id.* at 4012-14.

Commission order the Company to submit in its next rate case detailed information related to inspections and tree trimming associated with the hardening and Pole/PTMM programs.[379] He also lamented the opaqueness of the Company's actual investments in these program areas, particularly the fact that he was unable to ascertain the itemized non-capital components (trimming, inspections, labor, materials, overhead, installations, repairs) for these "capital" programs.[380] To address that issue, he recommended the Commission require the Company to provide clarification in its next rate case regarding how the Company treats maintenance-related expenses that are commingled into distribution capital programs.[381]

Staff witness Becker also raised concerns about the Company's approach to including inspection costs included in the hardening and Pole/PTMM programs as distribution capital and recommended that the Commission order Staff, the Company, and interested stakeholders to meet to evaluate the related issues and for the Company to provide additional supporting information.[382]

Company witness Uzenski filed rebuttal testimony responding to Mr. Ozar's and Mr. Becker's concerns.[383] The Company agreed to file reports supporting the capitalization policies related to inspection costs in the hardening and Pole/PTMM programs.[384] The Company moderately supported a stakeholder process to consider capitalization practices, and the Company rejected Mr. Ozar's concerns about capitalization of tree trimming costs and the installation/removal allocation. These rebuttal positions are addressed in turn below.

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[379] *Id.* at 4014-15.

[380] *Id.* at 4015.

[381] *Id.*at 4015-16.

[382] Becker Direct, 8 TR 5411-13.

[383] Uzenski Rebuttal, 7 TR 2776, 2790-92.

[384] *Id.* at 2776.

2. The Commission should adopt Staff's recommendations for a stakeholder meeting and additional information from the Company.

Responding to Mr. Becker's recommendation for the convening of a stakeholder group to evaluate capitalization procedures, Ms. Uzenski said, "I do not feel that a meeting on arcane accounting practices with all potential stakeholders is necessary or a good use of limited resources, but the Company does agree that a future discussion with Staff could be worthwhile."[385] MNSC supports Staff's recommendation for meeting, and appreciates the Company's willingness to do so. However, as a stakeholder interested in this issue, MNSC objects to the Company's assertion that it need only meet with Staff, not MNSC representatives and other stakeholders. Notably, Mr. Becker recommended the process should include "interested stakeholders," not "all potential stakeholders." MNSC witness Ozar provided a clear and comprehensive assessment of the Company's capitalization approach to inspections in the hardening and Pole/PTMM programs, and he went further than Mr. Becker by also articulating the policy rational underlying the issue, addressing a related concern for tree trimming costs, and identifying the issue of how costs are allocated between installation/removal. It is clear Mr. Ozar brings valuable and additional perspective to an "arcane" discussion about accounting practices.

The Company's characterization of this topic as "arcane accounting practices" is misplaced. It is no more arcane than many other relevant electric utility regulatory topics that the Commission, ALJ, and witnesses enthusiastically explore in great detail in these rate cases, like CIAC and depreciation schedules.

The Company suggests it would not be a good use of "limited resources" to include in the discussion about capitalization parties besides it and Staff. This argument is unfounded. If Ms. Uzenski were right when she claimed the topic is arcane, thus impliedly uninteresting and/or

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[385] *Id.* at 2790.

unimportant, that would surely self-limit the scope of willing participants in the discussion. To the extent the Company is concerned about *its* "limited resources" being spent on participation in an accounting policy discussion, the Commission should rest assured that interveners likely have even more limited resources. It is not reasonable to expect that unmanageable numbers of stakeholders are likely to show up to a meeting about the Company's distribution capitalization accounting practices. The Commission should accept Staff's recommendation as proposed, notwithstanding the Company's limited willingness.

3. The Commission should include tree trimming within the scope of further assessment of the Company's distribution capitalization practices, as recommended by Mr. Ozar.

Ms. Uzenski responded to Mr. Ozar's testimony regarding the capitalization of tree trimming costs in the hardening and Pole/PTMM program. Referencing Ms. Pfeuffer's direct testimony (4 TR 293[386]), Ms. Uzenski explained that tree trimming that is part of hardening "avoids duplicate tree trim maintenance work," "is done instead of maintenance trimming," and clears a larger area around assets to support "project needs."[387] She explained that Hardening is a capital project that replaces aging assets on each pole, and trees must be trimmed before this work can be executed. She maintained that it is acceptable to capitalize 100% of trimming in the hardening program because the program is not routine maintenance trimming.

These rebuttal points do not redeem the Company's capitalization of tree trimming in the hardening program. First, the rebuttal makes even more clear that trimming for hardening is a substitute for maintenance trimming. Hardening trimming displaces maintenance trimming. The Company is maintaining the line when it conducts circuit-level trimming as the first step in

[386] "As tree trimming is part of the scope of work for 4.8kV Hardening, the Company also reviews the tree trim schedule with the list of circuits to be hardened, this prevents circuits from being tree trimmed before the five-year cycle, avoiding duplicate work and maximizing the miles of circuits trimmed."

[387] Uzenski Rebuttal, 4 TR 2792.

hardening a circuit.[388] It is not just the next (future) round of maintenance trimming that is avoided by hardening-trimming; the Company provided data showing that the hardening-trim is also a maintenance trim. For the 29 circuits that were hardened in 2020, some were hardening-trimmed in each 2018, 2019, and 2020, but none had been previously trimmed since 2012 or earlier:[389]

	A	B	C	
1	MNSCDE-16.2b-01 Previous Tree Trim Year			
2	**Circuit**	**Last TT**	**Previous TT**	
3	SUB A0001	2020	2011	
4	SUB A0002	2020	2011	
5	SUB B0001	2019	2011	
6	SUB B0003	2019	2011	
7	SUB B0004	2019	2011	
8	SUB B0005	2019	2011	
9	SUB B0006	2019	2011	
10	SUB C0001	2020	2010	
11	SUB C0002	2020	2010	
12	SUB D0001	2018	2012	
13	SUB D0002	2018	2007	
14	SUB D0003	2018	2012	
15	SUB D0004	2018	2012	
16	SUB D0005	2018	2012	
17	SUB D0006	2018	2012	
18	SUB D0007	2018	2012	
19	SUB D0008	2018	2012	
20	SUB E0001	2019	2011	
21	SUB E0002	2019	2011	
22	SUB E0003	2019	2011	
23	SUB E0004	2019	2011	
24	SUB E0005	2019	2011	
25	SUB E0006	2019	2011	
26	SUB E0007	2019	2011	
27	SUB E0009	2019	2011	
28	SUB E0010	2019	2011	
29	SUB E0011	2019	2011	
30	SUB E0012	2019	2011	

But for hardening-trimming, the Company would have incurred the expense for maintenance trimming, but it is instead capitalizing the cost. Hardening-trimming costs are not insignificant:[390]

2018	2019	2020	2021	2022	2023
$ 9,994,263	$ 10,081,771	$17,904,719	$22,032,437	$23,644,582	$26,699,999

Mr. Ozar fully addressed the second point in Ms. Uzenski's rebuttal – that hardening-trimming is necessary before the other hardening work can be executed, and therefore it is appropriate to capitalize 100% of hardening-trimming.[391] He explained it is theoretically possible

[388] Ozar Direct, 4007-08, n.113.

[389] Ex MEC-98, p. 2.

[390] Ex MEC-97, p. 6 (Annual Hardening 4.8kV Tree Trim Capital Spend, 2018-2021); Ex MEC-21, pp. 5, 10 (projected hardening trim spending, 2022, 2023).

[391] Ozar Direct, 4008-10.

that hardening-trimming could serve two purposes: maintenance and construction. But the record does not support the assertion that the Company applies a different standard for construction trimming, nor that the nature of the work for construction versus maintenance is particularly distinct.

The Company did not address the USOA provisions that address tree trimming at all.[392] Trimming is an operating expense except the "initial cost" when overhead conductors are installed and replaced. The hardening program is not installing/replacing lines, it involves poles and pole top equipment. Mr. Ozar reviewed the USOA and found no support for the capitalization of trimming associated with pole work, particularly when it is a substitute for maintenance trimming.

Mr. Ozar provided compelling testimony that the Company is rebranding its maintenance tree trimming as hardening-trimming in order to capitalize what is otherwise a distinctly operating expense.[393] The hardening program is rationalized in part on the basis that the lines lacked proper maintenance and had become overgrown.[394] As the Company explained in U-20162 when first seeking approval for hardening, the City of Detroit lines that are the subject of hardening suffer poor reliability in part due to the age of infrastructure, and in part due to "abandoned and overgrown alleys" in Detroit.[395]

One final point bears noting related to the Company's rebuttal testimony regarding trimming capitalization. Ms. Uzenski states that hardening "replaces aging assets on each pole in the circuit," but the program is actually a bit different. Hardening replaces wooden crossarms with fiberglass, and then installs new pole top equipment, without regard to the age or condition of the

[392] Ozar Direct, 4005-08, 4010.

[393] *Id.* at 4010-12.

[394] *Id.* at 4011 (citing Ex A-23).

[395] Ex MEC-92, p. 12 (Case No. U-20162, Bruzzano Direct, 4 TR 728).

crossarms or equipment.[396] Regardless of the nature of the work, the Company has not supported its policy of capitalizing trimming costs that are included in the hardening program. The Commission should include this activity in the scope of additional required supporting documentation and as part of any stakeholder discussion.

4. **The Commission should require the Company to support its 80/20 installation/removal allocation.**

Ms. Uzenski addressed Mr. Ozar's concern about the 80/20 allocation between installation and removal costs for distribution capital costs.[397] She asserts, without support or citation, that 80/20 is "based on historical actual work performed."[398] Again, this is a non-responsive response. Mr. Ozar explained that he asked the Company in discovery for the basis for its 80/20 allocation and he got a non-response:[399]

> **MNSCDE-9.27a:** What is the basis for the 80/20 install/removal split for inspections, overheads, and crew costs? **Answer**: The Company's subject matter experts reviewed and investigated the work actually performed historically under the Pole and PTMM program and determined that the 80% install and 20% removal allocation for the assets worked on was the appropriate ratio.

Ms. Uzenski's rebuttal testimony is no more enlightening.

Ms. Uzenski opposed Mr. Ozar's recommendation for the Company to apply a simple 50/50 allocation between cost of removal (charged to accumulated depreciation) and replacement

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[396] Ozar Direct, 3971-72; Ex MEC-20 ("There is no test for cross arm condition. The company is hardening the circuit to increase its resilience until a later conversion is performed, and for this reason all wooden cross arms are replaced with the current standard fiberglass cross arms."); Ex MEC-26 ("Under the 4.8kV Hardening program all wood cross arms are replaced. In the Pole and PTMM program only cross arms that are damaged or defective are replaced.").

[397] Uzenski Rebuttal, 7 TR 2792.

[398] *Id.*

[399] Ozar Direct, 4013, n. 122.

(capitalized) for "construction-related" tree trimming costs.[400] She asserted that "Mr. Ozar's proposal appears only to choose a lower capitalization ratio and therefore is without merit." Again, this is not responsive to Mr. Ozar's testimony. He explained that "construction-related tree trimming must precede both removal and replacement activities, and there is no rational basis to favor one over the other with respect to the need for line clearance."[401] He further explained that, because trimming necessarily precedes inspection, the construction plan for a circuit cannot be known at the time of tree trimming. In other words, before the circuit is trimmed (around a decade after the last trim), the Company could not know what the construction work will involve, and the cost of trimming the line does not depend on the cost of asset replacement or removal. Mr. Ozar explained why he recommended 50/50 for construction-related tree trimming. The Company, on the other hand, has provided only a vague undocumented reference to "historical actual work."

Based on the reasonable and supported concerns raised by Mr. Ozar, and not refuted in rebuttal by the Company, the Commission should reconsider the 80/20 allocation unsupported, adopt a 50/50 allocation for construction tree trimming, and require more support, documentation, and justification for the 80/20 allocation for inspections, overheads, crew costs, and other related components in the next rate case.

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[400] Uzenski Rebuttal, 7 TR 2792.

[401] Ozar Direct, 8 TR 4014.

VII. COST OF SERVICE

A. Production Cost Allocation

1. The Fixed Costs of MERC should be Allocated to Fuel, not to Generating Plant.[402]

DTE witness Habeeb Maroun sponsored the Company's cost of service study. MNSC witness Douglas Jester testified that certain costs in the study should be allocated differently, to better reflect cost causation. One of these items is the fixed costs of the Midwest Energy Resources Company facility, or MERC. MERC is DTE Electric subsidiary located in Superior, Wisconsin that provides coal transportation services to DTE and third-party customers.[403] MERC's fixed costs total about $7.4 million in the test year.[404] DTE classifies these costs as production plant, where they are allocated primarily based on demand. MNSC witness Jester testified that the MERC costs should be classified as fuel costs, where they would be allocated primarily on total energy use.

The Commission has not specifically adjudicated the allocation of these MERC costs before. This is the first case in which DTE was required to break down its fixed production costs by plant, and therefore the first time the Company identified a specific amount of MERC costs allocated to production plant. Allocating MERC's fixed costs to fuel better reflects cost causation because MERC is a fuel handling facility and not a generating plant; because DTE has represented

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

- Direct testimony of Habeeb Maroun, 6 TR 1038-39;
- Direct testimony of David Milo, 7 TR 2664;
- Direct testimony of Douglas Jester, 8 TR 3840-46;
- Rebuttal testimony of Habeeb Maroun, 6 TR;
- Cross examination of Habeeb Maround, 6 TR;
- Exhibits A-32, A-16 Schedule F1.1, A-16 Schedule F1.5 Revised, and A-39 Schedule BB2;and
- Exhibits MEC-9, MEC-11, MEC-114, and MEC-117.

[403] Direct Testimony of David Milo, 7 TR 2664.

[404] Ex. A-32, p. 5, line 25, column ap; Jester Direct, 8 TR 3843.

that MERC generates fuel savings, which justifies assignment to energy under the NARUC manual; and because the current method creates a mismatch between the allocation of MERC's costs and the savings it generates. This mismatch shifts costs from customers who use more energy to customers who contribute more to peak demand.

DTE witness Maroun testified that production plant and plant-related costs are allocated based 75% on contribution to coincident peak demand in four summer months and 25% based on total energy use – or 4CP 75-0-25.[405] Mr. Maroun testified that fuel costs are allocated based 10% on contribution to coincident peak demand during all 12 months of the year and 90% based on total energy use – or 12 CP 10-0-90.[406] It has long been known that allocations that are primarily demand-weighted impose higher costs on residential customers than allocations that are primarily energy-weighted, to the benefit of primary customers.[407]

MNSC witness Douglas Jester testified that these MERC costs should be classified as fuel costs rather than production plant.[408] Mr. Jester explained that MERC is not a generating plant but instead is a cost of supplying fuel to DTE's coal-fired generating plants.[409] Mr. Maroun agreed on cross that DTE does not generate any electricity at MERC and MERC does not provide DTE with any capacity revenue.[410] Because DTE incurs the MERC costs to supply fuel and to generate revenue from third parties, Mr. Jester recommended that the Commission "determine that the full

[405] Direct Testimony of Habeeb Maroun, 6 TR 1028; Maroun Cross Exam, 6 TR 1072.

[406] Maroun Direct, 6 TR 1028; Maroun Cross, 6 TR 1073.

[407] See for example, Case No. U-17689, June 15, 2015, Order, pp. 22-23.

[408] Jester Direct, 8 TR 3843.

[409] *Id*.

[410] Maroun Cross, 6 TR 1087.

cost of MERC is a fuel cost for purposes of the unbundled cost of service study and direct that the unbundled cost of service study be corrected in this regard."[411]

In his rebuttal, DTE witness Maroun opposed changing the assignment of the MERC costs from production plant to fuel, for three reasons: (1) because the Commission has treated MERC's fixed costs in the same manner as DTE's production plant costs since at least the Company's 2008 rate case, U-15244; (2) because the treatment of MERC in the capacity charge calculation should be the same as in the cost-of-service study; and (3) because assigning MERC costs to fuel would be contrary to the Commission-approved methodology in place since the inception of the capacity charge calculation in Case No. U-18248.[412]

Cross-examination called these reasons into question, and revealed additional reasons that support assigning MERC costs to fuel. First, as to the treatment of MERC costs since DTE's 2008 rate case, the Commission Order in that case never discusses the assignment or allocation of MERC costs.[413] Nor does the allocation of MERC costs appear anywhere in the cost-of-service exhibit DTE filed in U-15244, which would only have addressed costs at a "very high level."[414] DTE never filed an exhibit breaking out MERC's fixed costs until this case.[415] The only discussion of MERC costs in testimony in U-15244 relates to the direct assignment of MERC-related PSCR refunds to power supply.[416] Mr. Maroun also agreed that the assigning MERC costs to production

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[411] *Id*. at 3846. Mr. Jester also recommended that MERC be removed from capacity revenue requirement for the capacity charge calculation.

[412] Maroun Rebuttal, 6 TR 1052.

[413] Case No. U-15244, Nov. 12, 2009, Order.

[414] Ex MEC-117, Exh A-13 Schedule E1 in Case No. U-15244; Maroun Cross, 6 TR 1091-92.

[415] Maroun Cross, 6 TR 1092-93.

[416] Ex MEC-114, Testimony of Martin Heiser in Case No. U-15244, exhibit p. 23, transcript p. 1296; Maroun Cross, 6 TR 1095-96.

plant in Case No. U-15244 would have meant that they were allocated using the 12CP 50-25-25 method in place at the time, which was a more energy-weighted method than 4CP 75-0-25.[417]

Second, with respect to Mr. Maroun's testimony that it would not make sense to classify MERC plant costs differently in the capacity charge calculation than in the cost-of-service study, he agreed on cross that Mr. Jester proposes to classify MERC costs as fuel for both purposes.[418] Do you understand DJ to be advocating that MERC plant costs should continue to be treated like fixed demand costs in the COSS?

Third, as to the Commission-approved methodology in place since the inception of the capacity charge calculation, the Commission Order in U-18248 indicates that DTE witness Thomas Lacey in that case agreed with Staff's exclusion of MERC costs from the capacity charge calculation.[419] Certainly that statement in the Order supports MNSC witness Jester's position on this issue.

Fourth, Mr. Maroun was not aware of how MERC was sized.[420] That said, as noted above, MERC provides fuel transportation-related services not only to DTE but also to third-party customers.[421] Therefore, it is hard to see how MERC could have been sized to meet DTE's coincident peak demand during four summer months. Therefore, allocating the costs of MERC to DTE customers based on their demand during those four peaks is not justified by cost causation.

Finally, the primary rationale for MERC's existence is to provide fuel savings for DTE. In its Order in Case No. U-5041, where the Commission originally approved the inclusion of MERC costs in rate base, the Commission cited DTE's projection that MERC would generate over a

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[417] Maroun Cross, 6 TR 1089-90.

[418] *Id*. at 1081.

[419] Case No. U-18248, Nov. 21, 2017, Order, p. 33; Maroun Cross, 6 TR 1099-1100.

[420] Maroun Cross, 6 TR 1098.

[421] Milo Direct, 7 TR 2664.

billion dollars in fuel cost savings.[422] The NARUC manual states that even at a generating plant (which MERC is not), "capital costs that reduce fuel costs may be classified as energy related rather than demand related."[423] If capital costs that reduce fuel costs at a generating plant can be classified as energy related, then surely capital costs that reduce fuel costs at a facility that is not a generating plant should be classified as energy related.

Doing otherwise causes a mismatch that inequitably shifts costs between customer classes. Mr. Maroun agreed that any fuel cost savings resulting from MERC would be allocated as fuel, using the 12CP 10-0-90 method.[424] Allocating the costs of MERC based on 4CP 75-0-25 thus does not match up with how the savings from MERC are allocated. Further, allocating costs with a demand-weighted method and savings with an energy-weighted method shifts costs from customers who pay a larger share of energy costs to customers who pay a larger share of production costs. For all of these reasons, the Commission should direct DTE to assign the MERC fixed costs to fuel.

2. All Fuel Handling Costs, including Labor, should be Allocated to Fuel.[425]

A second cost that MNSC witness Jester recommends reclassifying is the labor expense portion of fuel handling O&M. Currently, DTE classifies some fuel handling expense as variable O&M and allocates it using the energy-weighted fuel allocator discussed in the last section. But DTE breaks out the labor portion of fuel handling expense, which totals $17.775 million, and

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[422] Case No. U-5041, Sept. 17, 1976, Order, p. 3.

[423] Exhibit A-39, Schedule BB2, p. 21.

[424] Maroun Cross, 6 TR 1085.

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

- Direct testimony of Habeeb Maroun, 6 TR 1045-46;
- Direct testimony of Douglas Jester, 8 TR 3845-46;
- Rebuttal testimony of Habeeb Maroun, 6 TR 1055-56; and
- Exhibits A-16, Schedule F1.5 Revised and A-39, Schedule BB-2, NARUC Manual.

classifies it as a fixed production cost.[426] This results in fuel handling labor expense being allocated as a demand-weighted production cost in the UCOS and included as a capacity cost in the capacity charge calculation.[427] In rebuttal, DTE witness Maroun argued that breaking out labor costs from fuel handling expense is appropriate based on the NARUC Manual and the capacity charge methodology approved in Case No. U-18248. However, DTE's position is actually inconsistent with the NARUC Manual, and this issue was never specifically decided in U-18248.

MNSC witness Jester explained that labor expense for handling fuel "is obviously non-capacity-related and should be deducted in full from generation costs for the determination of capacity costs."[428] He recommended that "the Commission determine that all O&M costs for fuel handling are fuel costs" for purposes of both the cost-of-service study and the capacity charge calculation.[429]

In his rebuttal, DTE witness Maroun argued that "it is appropriate to exclude all labor dollars from variable O&M," and referenced a passage from his direct testimony.[430] Mr. Maroun also asserted that classifying fuel handling labor expense with fuel handling "is contrary to the Commission approved methodology in place since the inception of the capacity charge calculation in Case No. U-18248 and in subsequent rate cases."[431]

With respect to the first point, Mr. Maroun's direct testimony cited the NARUC Manual. The NARUC Manual instructs that certain FERC accounts should be classified between demand and energy, with labor expenses considered demand-related and material expenses considered

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[426] Ex. A-16, Schedule F1.5 Revised, p. 5, line 1.

[427] *Id*. at pp. 1 and 5.

[428] Jester Direct, 8 TR 3845.

[429] *Id*. at 3846.

[430] Maroun Rebuttal, 6 TR 1056, referencing his Direct at 6 TR 1045.

[431] Maroun Rebuttal, 6 TR 1056.

energy-related.[432] These included FERC accounts for steam expenses, steam from other sources, electric expenses, miscellaneous steam power expenses, and rents.[433] However, the accounts that NARUC recommends splitting between labor and materials do not include Account 501, Fuel Handling Expense.[434] Instead, Mr. Maroun states that he determined that Account 501 "should be handled in the same manner" as the other accounts.[435]

The NARUC Manual is <u>not</u> silent on how to classify Account 501, however. The NARUC Manual specifically indicates that Account 501 should be classified as energy-related.[436] So DTE's decision to break out labor expense from Fuel Handling O&M and treat it as production-related instead of energy-related is at odds with the NARUC Manual. That decision is also not justified by other information in this record, as Mr. Maroun was not aware of how plant staff is sized or whether that staff performs other tasks in addition to fuel handling.[437]

As to Case No. U-18248, there is no indication that the Commission specifically decided the issue of whether labor costs should be broken out of fuel handling expense and included in the capacity charge. The only reference in the U-18248 Order to fuel handling expense is a statement that "Staff identified all costs currently allocated using the production cost allocator (*with the <u>exception</u> of fuel handling costs*) as potentially capacity related."[438]

In sum, fuel-related costs – including fuel handling expense – should be allocated based on energy use. The NARUC Manual states that Account 501, Fuel Handling Expense, should be

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[432] Maroun Direct, 6 TR 1045, citing Ex A-39, Schedule BB-2, NARUC Manual, manual p. 35, exhibit p. 45.

[433] Ex A-39, Schedule BB-2, NARUC Manual, manual p. 36, exhibit p. 46.

[434] *Id*. at manual p. 38, note 4, exhibit p. 48.

[435] Maroun Direct, 6 TR 1045; Maroun Cross, 6 TR 1113.

[436] Ex A-39, Schedule BB-2, NARUC Manual, manual p. 36, exhibit p. 46; Maroun Cross, 6 TR 1113.

[437] Maroun Cross, 6 TR 1114.

[438] Case No. U-18248, Nov. 21, 2017, Order, p. 17 (emphasis added).

classified as energy-related. There is no contrary evidence in this record that demonstrates that the amount of labor cost incurred for handling fuel is determined by four coincident peak demand hours in the summer – or otherwise determined by peak demand at all. And while DTE may have been breaking labor out of Fuel Handling expense since Case No. U-18248, there is no indication in that Order that the Commission directed DTE to do so or otherwise commented on the issue at all. For all of these reasons, the Commission should adopt MNSC witness Jester's recommendation to classify all fuel handling expense as energy-related for purposes of the cost-of-service study and the capacity charge calculation.

VIII. RATE DESIGN & TARIFF ISSUES

A. D1.11 Time of Use Full Implementation[439]

DTE Electric proposed to comply with the Commission's order in Case No. U-20602 and transition residential customers on an opt-out basis to the new D1.11 rate.[440] The new D1.11 rate was designed as a time-based rate for non-capacity power supply.[441] MNSC witness Jester reviewed the Company's proposed rate and tepidly accepted it as a "small step in the right

[439] MNSC believes the following portions of the record are relevant to this issue:

- Willis Direct, 6 TR 927-90; Willis Rebuttal, 6 TR 971-72;
- Foley Direct, 6 TR 1146-52; Foley Rebuttal, 6 TR 1190-92;
- Ex A-16, Sch. F3, p. 11;
- Ex A-45, Sch. JJ1;
- Revere Direct, 8 TR 5127-37;
- Jester Direct, 8 TR 3849-53;
- Lucas Direct, 8 TR 3582-87; and
- Richter Direct, 8 TR 3233-40.

[440] Foley Direct, 6 TR 1146-48.

[441] Willis Direct, 6 TR 927-29.

direction."[442] Consistent with the position MNSC has advanced in the prior rate cases that addressed this issue, Mr. Jester supported the use of time-varying rates for capacity-related production and also distribution costs.[443] Capacity-related production and distribution costs are allocated based on class contribution to customer peak and class share of annual peak by voltage level, respectively.[444] As such, rates for these bill elements should reflect power usage. Mr. Jester recommended that the Commission accept Rate D1.11 and also direct DTE to propose modifications in its next rate case to include apply time-based rates for capacity-related production and distribution costs.[445] In rebuttal, DTE witness Foley presented an alternative TOU proposal (Exhibit A-45, Sch. JJ1), which applies time-based rates to both capacity and non-capacity portions of power supply.[446] Mr. Foley stated that the Company does not oppose the interveners' recommendations to extend TOU pricing to power-supply capacity rates. MNSC supports the Company's alternative TOU proposal.

MNSC maintains, however, that the Company must also take progress towards transitioning distribution costs to time-based rates. As Mr. Jester explained, distribution costs are allocated on class contribution to annual peak, and absent time-based rates, customers do not have the opportunity to respond to price signals correlated to patterns of usage.[447] No party filed rebuttal testimony opposing this recommendation. The Commission should instruct DTE to propose a time-based rate for distribution costs in its next rate case.

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[442] Jester Direct, 8 TR 3852.

[443] *Id.* at 3852-53; Case No. U-20162, March 6, 2019, PFD, pp. 262-64.

[444] Jester Direct, 3852-53.

[445] *Id.* at 38554-55.

[446] Foley Rebuttal, 6 TR 1191-92; Ex A-45, Sch. JJ1.

[447] Jester Direct, 8 TR 3852-53.

B. Rate Schedule D1.12 – Stable Bill Service Level

DTE Electric has proposed a new Stable Bill Service Level Rate ("Stable Bill Rate") for its residential customers that would shift a significant portion of their monthly bill away from energy charges to a fixed monthly demand charge. Under this proposed rate, the Company would use the average of a customer's three highest hours from their twelve prevailing months to determine a tiered monthly service level cost.[448] While even a single hour of higher energy use could push a customer into a higher demand charge tier, lower energy use would not lead to a reduced demand charge until twelve months after the three highest usage hours used to set the charge. The Company references this rate as a "voluntary tariff" but proposes to make it mandatory for new Rider 18 (distributed generation) customers in 2024.[449]

MNSC oppose the rate. A key reason among many for this opposition is that the fixed demand charge will disincentivize energy efficiency and other customer efforts to reduce their energy bills, such as distributed generation.[450] While the Company attempts to distinguish this rate from a "traditional" fixed bill rate, the Stable Bill Rate gives extremely limited ways for customers to have control over their bill prices, and still locks them into a similar pricing structure as these traditional fixed bill rates. Demand charges have been shown to be economically inefficient, and

[448] MNSC believe the following portions of the record are relevant to this issue:

- Foley Direct, 6 TR 1119-1186; Foley Rebuttal, 6 TR 1187-1233; Foley Cross, 6 TR 1240-1262;
- Jester Direct, 8 TR 3765-3862;
- Barnes Direct, 8 TR 4419-4482;
- Richter Direct, 8 TR 3124-3252;
- Revere Direct, 8 TR 5122-42;
- Lucas Direct, 3560-3646; and
- Exs. MEC-13, 118, 120, and 121.

[449] Foley Direct, 6 TR 1180-82.

[450] Barnes Direct, 8 TR 4453-62.

not reflective of cost causation.[451] In addition, fixed billing undermines the timely transition of residential customers to time-based (and cost-based) rates. The Company's primary rationale offered in support of this rate – that customers want consistent billing – is not well supported as the Company currently has other programs to achieve this goal. The Company is not proposing this rate as a pilot, but instead offers only vague claims that, if the rate were put in place, it would study the impacts of this type of billing structure on up to 10,000 customers. The Commission should reject the proposed Stable Bill Rate which, as detailed by witnesses Jester, Revere, Richter, Barnes, and Lucas, is not cost-aligned, inefficient, and would disincentivize efforts by customers to control their energy costs and shift to less carbon-intensive practices such as electric vehicles and electric heat.[452]

1. The Commission has Previously Denied Similar Fixed Bill Pilot Rate Programs

In the Company's 2012 rate case, the utility proposed a similar fixed bill rate, which the PSC rejected principally on the basis that the proposal would undermine energy efficiency savings requirements.[453] While the Company claims that its proposal here is not a traditional fixed bill rate, it similarly undermines energy efficiency for reasons stated above.

In Case No. U-20162, the Company again proposed a fixed bill pilot rate program, which was similar but not identical to its proposal in this case. The proposal in that case was for a pilot rate program for 5,000 eligible residential customers to pay a fixed monthly amount not subject to any adjustments for a one-year period.[454] MEC-NRDC-SC, Staff and the Attorney General objected to the proposal for various reasons, including the conflict with energy conservation goals,

[451] Jester Direct, 8 TR 3853-54; Exhibit MEC-13.

[452] *Id*. at 3853.

[453] Case No. U-17054, Dec. 20, 2012, Order, p. 3.

[454] Case No. U-20162, May 2, 2019, Order, p. 140.

overlap with the BudgetWise billing program, lack of price signaling, penalties, and other problems.[455] The Commission agreed with program opponents and rejected the proposal. Similarly, in Case U-20561, the Company once again proposed a fixed bill pilot rate program with modifications, including price signaling to customers, which the Commission also denied.[456]

The Commission should deny this rate again in this case, for the same main reason previous iterations have been denied in the past – it remains fundamentally counter-productive to energy efficiency and other efforts by customers to lower their energy bills, such as distributed generation. Additionally, instead of a pilot program with 5,000 customers, this would affect 10,000 customers and be required for new Rider 18 customers in 2024. The Company is proposing this rate again in a way that would have an even larger impact than their previous proposals as pilot programs, which could have lasting consequences on Michigan's energy efficiency.

2. The Stable Bill Rate Closely Resembles Traditional Fixed Bill Programs

The Company argues that the Stable Bill Rate is unlike traditional fixed bill programs because it (1) can vary month to month based on a customer's usage over the trailing twelve months, (2) is only fixed for the demand portion of the bill and the energy charges can vary month to month, and (3) the utility will not be charging a risk premium to customers.[457] However, these distinguishing factors are minimal at best. While a customer's bill under this rate uses the trailing twelve months instead of a calendar year, and the average of the three highest hours instead of the highest hour within those trailing twelve months, this structure still sets up similar issues as a fixed bill.

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[455] *Id.*, pp 143-44.

[456] Case No. U-20561, May 8, 2020, Order, p 142.

[457] Foley Direct, 6 TR 1159-1160; 1163-1164.

a. The demand charge may not be reflective of a customer's average energy use

The Stable Bill Rate has the potential to lock a customer into a higher fixed demand charge tier that does not reflect their typical energy usage.[458] A single high hour could distort their average, putting them in a higher Service Level Tier than their average usage. For example, if a customer had a high hour use of 7.5 kW, but their second and third highest were 3.5 kW, the average would fall under the 4-5 kW tier, and they would be charged a monthly fee corresponding to a higher tier than their actual usage, which would normally fall below 4kW. While a customer's energy charge could vary, it would not affect the majority of their monthly bill. A customer in this situation would be overcharged monthly for a tier that is not reflective of their actual energy use and would have to wait for twelve months for that hour to no longer be factored into their average.

Additionally, while the three highest hours cannot occur in the same day, they could still occur in the same week.[459] For example, if a customer had an extremely hot week in July, and incurred their three highest hours during that week, they would be locked into that average until twelve months have passed. This similarly would not reflect a customer's typical day-to-day usage.

b. A customer's demand charge only has the potential to increase within the twelve-month period

If a customer's demand charge is based off the average of their three highest hours in a twelve-month period, once those hours occur, a customer would need a whole twelve-month cycle from their highest hour to lower their charge. However, if within that period, a customer surpasses that highest hour, then their average and, potentially, their charge would increase for the next twelve months, with the customer immediately seeing an increase in their next bill. This rate locks customers into rates where they could see quick increases but would have to wait twelve months

[458] Foley Direct, 6 TR 1157; Foley Cross, 6 TR 1253-54.

[459] Foley Cross, 6 TR 1250.

to see a decrease. While the Company is not charging a risk premium, using the three highest hours would still prove costly to customers under this billing structure.

c. A customer's energy saving efforts would have minimal real time impacts on their monthly bill.

Once a customer is locked in, any energy savings they make through conservation actions will not immediately take effect on their demand charge. The Company's claim that customers could still lower their bill based on energy usage month to month also falls short as the impacts would be minimal. A typical customer's energy usage could only affect 20-25% of their bill, which would result in very little monthly cost-savings.[460] This is contrary to Michigan's energy efficiency goals, as it would disincentivize customers from taking energy saving actions, such as investing in energy efficient appliances.[461]

Thus, DTE's proposed Stable Bill Rate functions similarly as traditional fixed bill programs in a way that is contrary to Michigan's energy efficiency goals. Of concern, starting in 2024, the Company will be requiring new customers under Rider 18, which covers distributed generation, to be billed under this D1.12 structure. This could divert customers from choosing to take service under this Rider if they have minimal control over their energy cost savings.

3. The Company Offers Programs for Customers to Opt-in for More Consistent Billing

A core reason the Company gives for the Stable Bill Rate is that there is a customer need for consistent billing. However, DTE currently offers customers an opt-in program called "BudgetWise", which enables customers to pay their "annual energy bill in equal monthly installments to avoid the seasonal ups and downs of [their] natural gas and electric bills".[462] Unlike the

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[460] Exhibit MEC-118; Foley Cross, 6 TR 1244-50.

[461] Foley Cross, 6 TR 1248-49.

[462] Exhibit MEC-120.

stable bill rate, BudgetWise reflects changes in energy use, and if a customer does cut down on their energy, and is overcharged, their account would "be credited on [their] next bill".[463] BudgetWise offer customers the more consistent billing that the Company claims the Stable Bill rate is needed to achieve, while preserving the ability to see real-time effects of their energy efficiency, distributed generation, and other cost-saving actions that would be severely disincentivized under the stable bill rate.

4. The Company Has Not Sufficiently Responded to Critiques Opposing the Stable Bill Rate

Witnesses Barnes, Jester, Lucas, Revere, and Richter have all testified regarding their concerns over the Stable Bill Rate. These witnesses have pointed out this rate proposal falls short when it comes to "cost causation, economic efficiency, and revenue sufficiency"[464] and that there are no known tariffs that use a similar design rate to the Stable Bill Rate.[465] Witness Lucas makes the claim that this rate proposal is based on "fundamental misinterpretations of cost of service and rate design principles".[466] Witnesses Jester, Barnes, and Richter point to studies that highlight the inefficiencies of demand charges, along with Witness Richter pointing to experts critiquing demand charges especially when applied to residential customers.[467]

However, the Company has not specifically responded to these major concerns, apart from claiming that it "disagrees,"[468] and notes that any rate design will have some level of imprecision.[469]

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[463] Exhibit MEC-121.

[464] Barnes Direct, 8 TR 4428; Jester Direct, 8 TR 3853.

[465] Barnes Direct, 8 TR 4430; Richter Direct, 8 TR 3232.

[466] Lucas Direct, 8 TR 3567.

[467] Exhibit MEC-13; Richter Direct, 8 TR 3232-33.

[468] Foley Rebuttal, 6 TR 1193, 1196.

[469] Foley Rebuttal, 6 TR 1194, 1199-1200).

Given the strength and multitude of these Witness critiques, such a rebuttal is quite weak and provides little basis upon which to conclude that the Stable Bill rate is reasonable.

5. Conclusion of this section

The Commission should deny approval of the Stable Bill Rate. The Company's proposal does not show a need for such a rate as the Company already offers the BudgetWise program for customers looking for more consistent billing. The rate proposal would undermine energy efficiency and distributed generation efforts that are currently underway in Michigan. In many ways, this proposal has the potential to have a larger counterproductive impact on these efforts than proposals in the past given that Stable Bill Rate is not being proposed as a pilot, but as a rate that would eventually be mandatory for new Rider 18 customers. For each of these reasons, the Commission should reject the Stable Bill Rate, which does not meaningfully differ in function or impact from the Company's fixed rate proposals that the Commission has rejected in the past.

C. Contribution in Aid of Construction (CIAC) [470]

1. Introduction and background context for this subsection

In DTE Electric's last rate case, U-20561, MNSC requested that the Commission revisit DTE's Contribution in Aid of Construction (CIAC) policy.[471] After raising concerns with the obsolescence of the policy, new customer subsidization, and the increasing burden on rate base from Company new customer contributions, MNSC witness Jester proposed an alternative CIAC approach that would be based on the new customer's expected distribution revenues rather than

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[470] The record related to CIAC consists of the following:

- Willis Direct, 6 TR 949-61;
- Willis Rebuttal, 6 TR 996-96;
- Ozar Direct, 8 TR 4034-37;
- Exs MEC-15, MEC-127.

[471] See Case No. U-20561, May 8, 2020, Order, pp. 95-98.

total annual revenue. This proposed change, tying the Company contribution to the new customer's distribution revenue, would have resulted in approximately 20% reduction to new business capital expenditures. While the ALJ recommended the Commission adopt MNSC's approach, with a one-year delay period to soften the transition, the Commission declined to accept that recommendation.[472] The Commission found MNSC's specific proposal (contribution limited to 4.5 times estimated distribution revenue) was insufficiently supported. But the Commission did recognize the need to do *something* about CIAC:

> However, the Commission finds that it would benefit from additional information on whether the current CIAC policy fully reflects cost-of-service principles. As such, in the company's next rate case, the Commission directs DTE Electric to: (1) provide supplementary, substantial, and specific support of the current CIAC model, (2) demonstrate that the current CIAC model is cost-of-service based, (3) provide evidence specifically showing how the overall revenues from new customer connections help offset other customer costs, and (4) provide details regarding how new customer connections drive upgrades to the system that may benefit other customers.[473]

In Consumers Energy's rate Case No. U-20697, following MNSC's similar recommendations to revisit utility CIAC policy, the Commission directed Staff to convene a workgroup to address Consumers' CIAC policy.[474] The Commission noted that CIAC policy predates unbundling, but "developing a new approach should not be rushed."[475]

Staff convened the CIAC workgroup in 2021 and published a final report on January 15, 2022.[476] The report documents differences of perspectives among workgroup participants, and concluded with the following recommendations:

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[472] *Id.* at pp. 96-97.

[473] *Id.* at 98.

[474] Case No. U-20697, Dec. 17, 2020, Order, pp. 330-32.

[475] *Id.* at 331.

[476] Ex MEC-15 (Case No. U-20697, Staff's Jan. 15, 2022, CIAC Workgroup Report).

- Further consider updating the cost per foot of line extension presented in tariffs;
- Only change CIAC policy in general rate cases and not standalone proceedings; and
- Continue CIAC workgroup meetings to further develop known issues and gather data for further analysis. Stakeholders may use the discussion and data to make proposals in future cases.

The Commission has taken no further public action on CIAC policy since the Staff report.

Shortly after Staff filed the CIAC workgroup report, DTE Electric filed this rate case. Company witness Willis addressed the Company's CIAC policy, responding to the Commission directive in U-20561.[477] Mr. Willis first described the perceived challenges with the CIAC proposal that MNSC witness Jester presented in U-20561 (allowance equal to 4.5 times distribution revenue),[478] then supported retention of the Company's current CIAC model.[479] Finally, Mr. Willis demonstrated the difference between the MNSC-20561 CIAC proposal and the Company's current CIAC policy by discussing the difference in impacts to the new customers and the cost to existing customers between the two policies.[480]MNSC opposes the Company's do-nothing approach to CIAC policy.

MSNC witness Ozar presented the position of MNSC related to DTE Electric's CIAC policy.[481] He reiterated the concerns raised in the last rate case: that there is a cross-class subsidy resulting from the utility contribution being based in both distribution and power supply rates,

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[477] Willis Direct, 6 TR 949-61.

[478] *Id.* at 951-53.

[479] *Id.* at 953-57.

[480] *Id.* at 957-58.

[481] Ozar Direct, 8 TR 4034-37.

where larger customer rates are heavily weighted to power supply, but where the net revenue requirement for the line extensions remains allocated to distribution and collected through distribution rates, which are predominantly collected from smaller customer classes.[482] After discussing these concerns, he recommended an alternative "next step" than the reform policy proposed by Mr. Jester in U-20561 and discussed by the workgroup: he recommended consideration of an approach where revenue requirements of the line-extension allowance attributed to projected power supply revenues (capacity and energy) would be assigned to power-supply revenue requirements and recovered through power supply charges.[483] This would leave the revenue requirement of line extension allowances that are attributed to distribution revenue (per existing CIAC formulas) to continue being allocated to distribution revenue requirement and recovered in distribution charges. This approach would ameliorate the cross-class subsidy concern and it would not change the impact to new customers (the primary concern addressed in Mr. Willis' testimony), but rates would more accurately reflect the line-extension allowances available to each class. Mr. Ozar recommended that, if the Commission finds merit in this approach or modifications of it, that it direct Staff to work with the CIAC workgroup to explore this concept and work out details with the participants, then provide an additional report.[484]

2. The Company has not met the directives in U-20561.

Mr. Willis opposed Mr. Ozar's reasonable next-step recommendation on the basis that "[s]ystem work for line extensions is not an investment in production plant and therefore credits should not be recovered in the production (power supply) revenue requirement."[485]

[482] *Id.* at 4035.

[483] *Id.* at 4036-37.

[484] *Id.* at 4037.

[485] Willis Rebuttal, 6 TR 996.

Notwithstanding the Commission order in U-20561, which questioned whether the current approach meets current cost of service models, as well as Staff's recommendations for additional study, it seems the Company is satisfied with the status quo. The following sections address the Commission directives in U-20561.

a. The Company did not "provide supplementary, substantial, and specific support for the current CIAC model."[486]

The Company did not meet the first part of the Commission's directive in U-20561. The Company described the current CIAC approach, states it is transparent about the amount of credit for new customers, "maintains the value proposition previous customers received," and allows the Company to attract to customers.[487]

This recitation fails to address the Commission's request. It is a pitch for the status quo, nearly identical to the Company's position in U-20561; it is not supplementary, substantial, nor specific. In U-20561, DTE argued as follows:

> DTE Electric disagrees that that the CIAC policy should be changed at all. Company witness Mr. Bloch explained that Mr. Jester's proposal should be rejected for three reasons. First, it would create a disincentive for new customers looking to locate in DTE Electric's service territory at a time when DTE Electric's growth rate is low. New customers contribute to fixed expenses, thereby lowering costs for other customers. Second, it does not properly recognize the total incremental value (contribution) provided by new customer load. Third, it would move away from a long-standing policy and value proposition that existing customers have received, but new customers would not receive (8T 2293).[488]

[486] Case No. U-20561, May 8, 2020, Order, p. 98.

[487] Willis Direct, 6 TR 951-52.

[488] Case No. U-20561, DTE Electric Exceptions, p. 52.

The Commission should not maintain the current policy on the basis that it was previously approved by the Commission.[489] DTE's standard contribution amount was approved by the Commission in 1976.[490] In that proceeding, DTE proposed to increase customer contributions for new connections to address cash flow or financial problem that DTE had experienced.[491]

According to that Order, DTE witness Mayotte acknowledged that "existing customers do to an extent subsidize those customers who request an extension," and that the ratio of total investment to total annual revenue for an average customer in different classes ranged from 2.2 to 3.2 to 1.[492] Staff witness Croy supported modifying DTE's proposal, suggesting a reasonable investment to revenue ratio was 2:1. While this ratio "would still require some subsidization of new customers by existing customers, the new customers would be contributing more towards the new facilities than they are now required."[493] The Commission agreed with Staff's proposal and adopted rules providing DTE's contribution to new connections is based on two years of estimated annual revenue.

Following that, the Commission in 2012 in an *ex parte* proceeding approved the alternative contribution allowance table for large secondary customers.[494] In twin *ex parte* proceedings filed by DTE Electric and Consumers Energy, the Commission allowed an amendment to each utility's rate book to offer the optional standard allowance for new or expanding large commercial and

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[489] Willis Direct, 6 TR 951.

[490] Case No. U-4738, Oct. 18, 1976, Order Approving Application and Denying Motion to Reopen Record, Exhibit A, Rule B-3.3 EXTENSION OF SERVICE.

[491] *Id.*, pp. 2-3, 6.

[492] *Id.*, p. 4.

[493] *Id.*, p. 5.

[494] See Willis Direct, 6 TR 953-54, referencing Case No. U-17055.

industrial customers.[495] As recited by Mr. Willis, Commissioner Quackenbush was quoted in a press release issued the day the twin orders were approved, stating the change "will make Michigan more attractive to businesses" and would "improve Michigan's economic development climate."[496] But the Commission did not address the cost impact of the CIAC policies (standard or table) on other rate classes.[497] The *ex parte* proceeding lacked fact-finding rigor of an adversarial process. The Commission concluded there would be no change in rates or cost of service to any customer because the tariff was optional.[498] It is apparent that there was no analysis or record related to the impact of the subsidy on ratepayers generally, nor related to equity between different rate classes.

The fact that the CIAC policy has been in place for 45 years supports revisiting it, not maintaining it unchanged. In the interim years, rates and rate-related policies have been regularly modified, from rate unbundling, technology improvements, and evolving cost of service modeling. The Commission is not constrained to perpetuate a policy because it is been in place for decades. It may have been reasonable for the Commission in 1976 to find it appropriate for ratepayers to subsidize new customers to generate cash flow for the Company, and in 2012 to find that ratepayers should fund economic development incentives in DTE's service territory, but that does not mean this Commission in 2022 is bound to perpetuate those policies.

The Commission also should not maintain the current policy on the basis it provides transparency about the amount of credit for potential new customers considering moving or

[495] Case No. U-17055, Oct. 31, 2012, Order; see also Case No. U-17055, Oct. 31, 2012, press release, indicating that similar approaches were approved for both DTE and Consumers.

[496] Ex MEC-126.

[497] See Case No. U-17055, Oct. 31, 2012, Order; see also DTE application filed in U-17055.

[498] Case No. U-17055, Oct. 31, 2012, Order, p. 2.

expanding in DTE's service area, as DTE argues.[499] There is no reason that modifying the CIAC policy in the context of a rate case would reduce transparency about construction costs for new customers.

b. The Company did not show "the current CIAC model is cost-of-service based."[500]

On this point, Mr. Willis states that customers contribute to the margin, and fixed cost recovery, for both distribution and power supply assets on the system, based on their rate, which is the basis for the current approach.[501] He argues that a distribution-only credit would not appropriately reflect the contribution to both power supply and delivery. He further states that both the allowance table and standard allowance methods calculate margin contributions based on margins and the approved cost of service.[502]

The flaw in this argument that the current credit is based on total revenue, but many customers who particularly benefit from large credits contribute minimally to distribution asset cost recovery. The amount of the credit is based on the customer's projected total revenue, which is tied to the "increase in energy/demand associated with the project" (*i.e.,* the new connection(s)).[503] Impugning the 20561-MNSC proposal because it shifted the credit entirely to distribution does not absolve the current credit of its fundamental flaw: the class of customers who benefit the most from the credit contribute the least to cost recovery for the funded projects.

The Company's argument that new customers will contribute to both distribution and power supply asset cost recovery so it is appropriate to set the credit based on total revenues also begs the question. In U-20561, MNSC supported updating the CIAC policy so that it reflects the

[499] Willis Direct, 6 TR 951.

[500] Case No. U-20561, May 8, 2020, Order, p. 98.

[501] Willis Direct, 6 TR 953.

[502] *Id.* at 959.

[503] Ex MEC-127, p. 1.

degree to which the new customer will contribute to distribution (where the project cost is allocated) and power supply cost recovery. The Commission agreed with the premise of MNSC's position (the record supported a need to revisit the policy), although it was unwilling at that time to adopt the recommended solution.

DTE's position that new customers who receive credits will contribute to both distribution and power supply, without providing supporting data of the degree or amount they contribute to each, does not address whether the current credit or cost recovery policies reflect cost of service.

c. The Company did not "provide evidence specifically showing how the overall revenues from new customer connections help offset other customer costs."[504]

The Company's position is that supporting new primary customers by maintaining the current credit methodology and maintaining the current allocation of connection costs to distribution rates is a net benefit.[505] The Company states that the allowance provided to customers will be fully recovered over the contract term, and margins beyond the contract period contribute to fixed costs. The Company provided an analysis showing that 90 unique projects to connect new large customers between 2018 and 2020 added distribution plant costs of $57,936,822, and the customers contributed $17,643,272 to the projects under current CIAC policies.[506] The Company's position may be illustrated as follows: the cost of the project to connect Customer 13 was $1.225 million; the credit amount for Customer 13 using the standard table was $1.65 million, based on its projected revenue (energy/demand) under its rate schedule, over a period of 0 to 5 years.[507] The Company's theory seems to be that, after the contract period, Customer 13 will have provided total

[504] Case No. U-20561, May 8, 2020, Order, p. 98.

[505] Willis Direct, 6 TR 690.

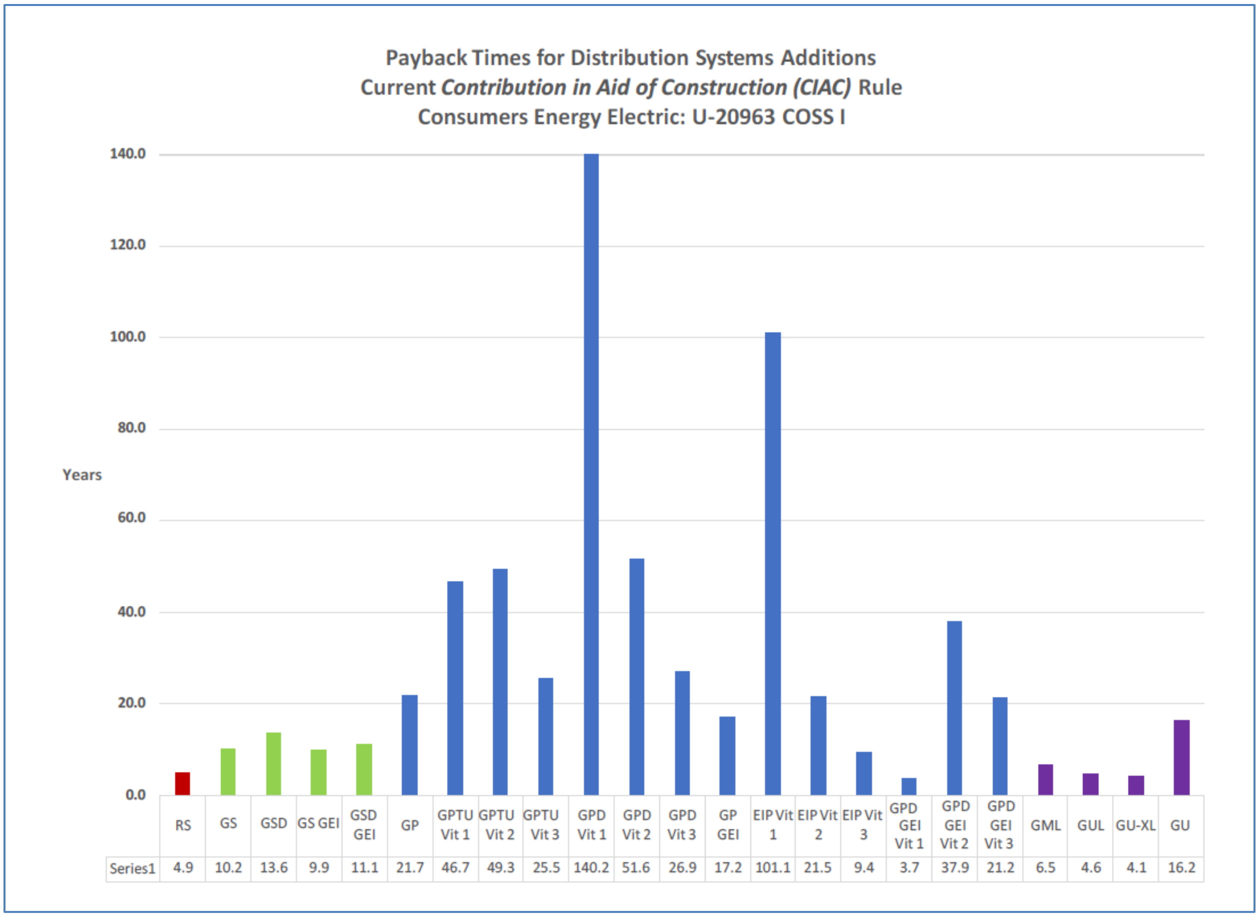
[506] Ex MEC-127, p. 10 (sum of total cost in column (b) and CIAC per current tariff in column (f)).

[507] Ex MEC-127, p. 1 (methodology), p. 10 (table).

revenue in excess of the cost of the distribution project cost, plus they will contribute to other surcharges, so they helped offset other customer costs.

This assessment is simply not responsive to the issue. During the contract period, revenues from Customer 13 are driven by that customer's energy and demand to offset power supply costs. After the contract terminates, if Customer 13 remains a DTE customer, then its revenues will continue to reflect primarily production costs. This analysis provides no information whatever about how much distribution revenue Customer 13 is expected to contribute in the period to offset the ratepayers' distribution investment. Company revenues from Customer 13 for production offset Company power supply costs in relation to power supply cost of service. But this new project was added entirely to distribution plant, and depending on which rate class Customer 13 is in, it is likely contributes minimally to distribution costs. MNSC demonstrated the variability in number of years for a customer's distribution revenue to offset distribution project investment depending on rate:[508]

[508] Ex MEC-15, p. 23.



The 90 unique projects connecting new large customers in 2018, 2019, and 2020 added net $40.294 million ($57.936 million project costs less $17.643 million in CIAC) in distribution plant.[509] Those costs will be recovered through distribution rates for years according to the depreciation schedules. MNSC inquired in discovery how much revenues were actually generated as a result of the project, and the Company responded that it does not track revenues by line extension or project.[510] There is no record in this proceeding specifically showing how revenues from these new connections help offset other customer costs.

[509] Ex MEC-127, p. 10.

[510] *Id.* at pp. 4, 9.

d. The Company did not provide "details regarding how new customer connections drive upgrades to the system that may benefit other customers."[511]

MNSC inquired in discovery about the projects that resulted in $40 million in distribution project costs incurred between 2018 and 2020.[512] The Company objected that the information is confidential and commercially sensitive, and then referenced the workpaper supporting the projects.[513] There is no record for the Commission to determine what projects ratepayers funded, nor what upgrades (if any) they provided to the system, nor whether or how the customers who will primarily contribute distribution revenues to recovery the project costs will benefit from the spending. There is also no information about which rates the customers are on, nor how many years they are committed to take service under the allowance table. There is also no information about who the new customers are, nor what industry they are in, nor what economic activity they generate. Ratepayers who contribute distribution revenue must simply trust this substantial investment is fair, reasonable, and beneficial.

3. It is unreasonable to maintain the status quo CIAC policy.

There are numerous problems with the Company's do-nothing approach. Principally, the Company rationalizes the current policy on the basis that it benefits "higher voltage customers who bring added economic activity to the region," whereas shifting to a distribution-rate based credit (MNSC's position in U-20561) would "heavily preference lower voltage customers."[514] Mr. Willis characterizes this shift as inequitable. The Company's attack of the 20561-MNSC proposal (credit is 4.5 times distribution revenue) goes to great lengths to demonstrate that the 20561-MNSC

[511] Case No. U-20561, May 8, 2020, Order, p. 98.

[512] Ex MEC-127, p. 8 ("what work was done where, why, by whom, at what cost, and how CIAC was determined").

[513] *Id.*, pp. 7, 8, 10 (workpaper).

[514] Willis Direct, 6 TR 952-53.

approach would increase connection costs for new primary customers, which are currently recovered through distribution rates. MNSC acknowledges the result of CIAC tied to distribution revenue would shift costs for new primary connections to those customers. The present approach allocates those costs heavily to existing and future residential and small commercial customers, who contribute substantially more to distribution cost recovery. The Company openly supports the current policy on the basis of economic development and regional cost competitiveness.[515] At bottom, the Company's position recognizes this burden and rationalizes it as fair and justified because of potential added economic activity resulting from the new primary customers.

The Company's position that it is "equitable" for residential and small commercial ratepayers to be allocated disproportionate costs for new connections in order to entice new customers to the region is empirically thin. DTE presented no evidence that new customers located in DTE's service area because of its CIAC policy. Nor is there any basis to conclude that adjusting the CIAC policy to derive the ratepayers' contribution based on new distribution rather than new total revenue would dissuade new customers from locating in DTE's service area. Nor is there any way for the Commission to evaluate the soundness of DTE's position because DTE maintains that information about the new connection projects is secret.[516]

There is no policy rationale supporting why residential and small commercial customers and not primary customers should shoulder a disproportionate burden of that cost. So long as the ratepayer contribution to new customers and load is based on estimated total revenue while the investment added wholly to distribution plant, this policy will continue to burden classes with relatively high distribution rates (*i.e.*, residential) and subsidize classes with lower distribution rates (*i.e.*, industrial).

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[515] *Id.* at 953-54.

[516] Ex MEC-127, p. 8.

Mr. Ozar recommended the Commission maintain the Staff-led CIAC workgroup, and explore a change in how allowances for new connection projects are allocated.[517] Specifically, he offered that revenue requirements for the allowance that are attributed to distribution revenue be attributed to distribution, and revenue requirements attributed to power-supply revenues assigned to power supply revenue requirements.

In rebuttal, Mr. Willis argued this would be inappropriate because credits for line extensions support investment in distribution plan (transformers, conductors, poles, etc.).[518] Since the new connection investments are not in production, credits should not be recovered through power supply revenue requirement.

The Company's response misses the point of MNSC's concern with the current approach, which is the disconnect between additions to distribution plant for line extension justified on the basis of expected customer additions based primarily on Company power supply revenue. From 2018 to 2020, for the 90 unique projects in its analysis, the Company provided credits or allowances of $40 million based on expected revenues from the customers. Some of those expected revenues are for distribution and some are production. Mr. Ozar's approach would reflect the fact that the allowance amount is effectively a ratepayer "advance" on projected revenue from the new customer, in proportion to the revenues contributed to distribution and production.

Mr. Willis did not address Mr. Ozar's related recommendation that the Commission address proposed CIAC modifications through the Staff workgroup. The Commission has not addressed the Staff recommendation to continue the CIAC discussions. Given the lack of detailed information provided in the context of this rate case to support the continuation of current CIAC policies, the Commission should direct the Staff to reconvene and elicit from DTE the necessary

[517] Ozar Direct, 8 TR 4036-37.

[518] Willis Rebuttal, 6 TR 996.

information to evaluate reasonable modifications the update the policy and reflect cost of service. This includes information about details about projects and costs in the context of customer rates, together with expected and actual revenue information (production and distribution), to enable the Commission and stakeholders to develop a modern and equitable CIAC policy.

D. Distributed Generation Program – Introduction (Rider 18) [519]

1. Introduction to this section.

DTE Electric has proposed to raise the "cap" on its Distributed Generation ("DG") program to 3.0% of its average instate peak load for Full-Service customers during the previous 5 calendar

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

- Direct Testimony of Justin R. Barnes (8 TR 4422-82);
- Rebuttal Testimony of Adella F. Crozier (7 TR 2395-6);
- Direct Testimony of Brian Donovan (8 TR 4176, 8 TR 4178-80, 8 TR 4182-93);
- Direct Testimony of Neal T. Foley (6 TR 1122, 6 TR 1167-86);
- Revised Rebuttal Testimony of Neal T. Foley (6 TR 1188, 6 TR 1203-33);
- Cross Examination of Neal T. Foley (6 TR 1238-9);
- Direct Testimony of Douglas B. Jester (8 TR 3850, 8 TR 3854, 8 TR 3855-8, 8 TR 3862);
- Direct Testimony of Jackson Koeppel (8 TR 4259, 8 TR 4264, 8 TR 4291, 8 TR 4296);
- Rebuttal Testimony of Jackson Koeppel (8 TR 4351);
- Direct Testimony of Kevin S. Krause (8 TR 5506-10);
- Rebuttal Testimony of Kevin S. Krause (8 TR 5510-B-E);
- Revised Direct Testimony of Kevin Lucas (8 TR 3567, 8 TR 3600-46);
- Direct Testimony of Cody S. Matthews (8 TR 5377, 8 TR 5383-7);
- Rebuttal Testimony of Cody S. Matthews (8 TR 5389-91);
- Direct Testimony of Nicholas M. Revere (8 TR 5127, 8 TR 5138-141);
- Rebuttal Testimony of Nicholas M. Revere (8 TR 5144-52);
- Direct Testimony of Robert Rafson (8 TR 3258-88);
- Direct Testimony of John Richter (8 TR 3128, 8 TR 3134-41, 8 TR 3150-3233);
- Direct Testimony of Laura S. Sherman (8 TR 4376, 8 TR 4391-6, 8 TR 4417);
- Direct Testimony of Melissa Stults (8 TR 3316-7, 8 TR 3337-41);
- Direct Testimony of Aaron Willis (6 TR 918, 6 TR 934-8);
- Rebuttal Testimony of Aaron Willis (6 TR 968, 6 TR 970, 6 TR 972-4, 6 TR 1003-4);
- Direct Testimony of Fang Wu (8 TR 3347-8, 8 TR 3350-77);
- Exhibits A-16, A-28;
- Exhibits AA-23, AA-26, AA-27, AA-28, AA-29, AA-30, AA-33, and AA-34;

years in exchange for the Commission's approval of two changes to Rider 18: (1) requiring all Rider 18 customers to take service under the proposed D1.12 rate schedule (in other words, using D1.12 for inflow); and (2) reducing outflow credits to locational marginal price ("LMP").[520] MNSC and multiple other parties oppose DTE's proposed modifications to the Company's DG program and encourage the Commission to reject DTE's offered bargain. MNSC also support many of the criticisms by the CEO, the City of Ann Arbor, Staff, EIB, GLREA, and DAAO of DTE's DG proposals. Finally, MNSC respectfully requests that the Commission reject all of DTE's proposed changes to its DG program and instead require that Rider 18 outflow bill credits be equal to the production cost at the time of outflow, inclusive of transmission costs, and further direct DTE to provide an analysis in its next case of the cost of service for behind-the-meter DG customers.

2. DG Inflow issues:

a. <u>DTE's proposal violates PURPA, the Federal Power Act, and Michigan law because it is anti-competitive and discriminatory and DTE has not demonstrated that its requirement that residential DG customers take service under a different rate schedule is due discrimination.</u>

The Public Utility Regulatory Policies Act of 1978 ("PURPA") requires electric utilities to purchase energy that qualifying facilities ("QFs") offer "at rates that are 'just and reasonable to the electric consumer of the electric utility and in the public interest' and that do not 'discriminate

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- Exhibits CEO-32, CEO-33, CEO-34, CEO-45, CEO-46, CEO-47, CEO-48, CEO-49, CEO-50, CEO-51, CEO-52, CEO-53, CEO-54, CEO-55, CEO-56, and CEO-57;
- Exhibits DAO-10, DAO-11, and DAO-20;
- Exhibits GLREA-2, GLREA-3, GLREA-4, GLREA-5, GLREA-6, GLREA-7, GLREA-9, GLREA-10, GLREA-11, GLREA-12, GLREA-13, GLREA-14, GLREA-16, and GLREA-17;
- Exhibit MEC-12; and
- Exhibit S-14.3.

[520] Foley Direct, 6 TR 1169, 1182.

against qualifying cogeneration and small power production facilities.'"[521] Section 205 of the Federal Power Act also prohibits undue discrimination "with respect to any transmission or sale subject to the jurisdiction of the Commission[.]"[522] Charging customers different rates when those customers have similar costs of service constitutes undue discrimination because it is an "unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[523] Similarly, MCL 460.557(4) prohibits charging similarly-situated customers different rates.

MNSC witness Jester noted that because most of the distributed generation under Rider 18 is behind-the-meter solar generation and therefore a PURPA QF, DG customers should be compensated for their outflow at DTE's avoided cost – which is very likely greater than the proposed outflow credit of locational marginal price.[524] Mr. Jester also observed that DTE has failed to show that requiring DG customers to "take service under a different rate schedule than other residential customers" is "due discrimination."[525] To demonstrate that requiring residential generators to take service under D1.12 is due discrimination, DTE "would need to demonstrate that the cost of service for such customers is such that they would not pay appropriate revenue under the alternative tariffs and that the tariff they propose to require for customers with distributed generation more accurately charges such customers than the alternative tariffs."[526] DTE cannot

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[521] Case No. U-18091, Sept. 26, 2019, Order, p. 2 (quoting 18 CFR 292.304(a)(1)-(2)).

[522] 16 USC §824d(b).

[523] *Id.* See also Calpine Corp., *et al*, 163 FERC ¶ 61,236, *17 n 112 (2018) ("Typically, undue discrimination cases involve a seller charging a different rate to similarly-situated customers[.]").

[524] Jester Direct, 8 TR 3855-6 (citing Case No. U-18091, September 26, 2019, Order).

[525] *Id.* at 3856.

[526] *Id.*

have done this because DTE has not calculated the cost of service for DG customers in the same way as it has for all customers in the unbundled cost of service study.[527]

City of Ann Arbor witnesses Fang Wu and Melissa Stults also presented evidence showing that DTE's DG proposal is anti-competitive. Witness Stults argued that the proposed D1.12 rate structure is anti-competitive because "it is effectively an exit fee applied only to customers that install distributed energy systems" and therefore has the effect of "intentionally making distributed solar resources far too expensive and pushing climate conscious ratepayers into the MIGreenPower program . . ."[528] Forcing solar customers to take service on the D1.12 rate penalizes those customers alone and is likely to deter DG to the point where the cap is "moot".[529] Similarly, CEO witness Lucas showed that this mandatory Rider 18 tariff causes a bill shock that "will be sizeable and immediately felt upon implementation."[530]

Dr. Stults also noted that DTE disincentivizes distributed energy resources by "treat[ing] excess energy generated through rooftop solar systems as waste" under the D.1.12 tariff.[531] Ms. Wu provided the analyses showing that proposed D1.12 imposes a demand charge on DG customers "unrelated to the actual effect on the system" and saddling new solar customers with higher capacity and distribution charges than what they currently pay.[532] These charges artificially make the MIGreenPower program more attractive "by eliminating the opportunity for payback of customer-funded systems if the excess power is used instead of disposed of, and by lengthening

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[527] *Id.*

[528] Stults Direct, 8 TR 3337-38.

[529] *Id.* at 3338-39.

[530] Lucas Revised Direct, 8 TR 3605.

[531] Stults Direct, 8 TR 3329.

[532] Wu Direct, 8 TR 3348.

the payback period of self-supply systems by eliminating the opportunity to allow excess power to be placed on the grid."[533]

DTE's DG proposal discriminates against QFs by undercompensating for outflow and deterring competition with its MIGreenPower program. DTE has also failed to show that the cost of service for DG customers is so different, or that they are otherwise so differently situated from other residential customers, that they require they would not pay appropriate revenue under the "prevailing residential customer tariffs."[534] Because DTE has not justified requiring DG customers (and those customers alone) to take service under this unattractive tariff, the Commission should reject DTE's proposal that all Rider 18 customers must use D1.12 for inflow. DTE appears to be attempting to deter participation in a green program by pricing out customers, and the Commission should again decline to approve it.

b. <u>MNSC's recommendations are a necessary next step for DTE to create an attractive and fair DG program.</u>

In addition to its request that the Commission reject DTE's proposal to require DG customers to take service under rate schedule D1.12, MNSC recommends that the Commission require DTE to conduct and provide in its next rate case an analysis of the cost of service for DG customers. This analysis should use "the same methods to allocate costs as are used in its overall unbundled cost of service study," and should "provide a comparison of that cost of service to the revenue that will be paid to DTE Electric by customers with distributed generation that choose to be in each of the available rate schedules."[535] The Commission should also require DTE to show

[533] *Id.* at 3376.

[534] Jester Direct, 8 TR 3856.

[535] *Id.* at 3857.

how discrepancies between the revenue and cost of service for DG customers compares to these same discrepancies for non-DG customers.

c. DTE's defense of its DG outflow proposal and objection to MNSC's recommendations are unavailing because they are entirely based on DTE's flawed cost shifting argument and misinterpret MNSC witness Jester's testimony.

DTE witness Foley attempted to defend DTE's DG outflow proposal by arguing that it is neither anti-competitive nor discriminatory because there is a cost shift from DG to non-DG customers that justifies "the requirement that future DG customers take service on a rate that addresses the cost shift without being discriminatory."[536] Mr. Foley disputes witness Lucas's contention that a cost shift does not exist by referring back to the argument in his direct testimony "that DG customers reduce the amount they contribute toward the distribution system by reducing the amount of energy they inflow from the company." [537] He also asserts that costs could be shifted onto non-DG customers in future rates that "reflect the same level of costs with lower inflowed energy" because inflow decreases do not impact fixed delivery costs.[538] Finally, Mr. Foley states that DTE's proposals are not intentionally deterring participation in distributed solar and pushing ratepayers into because DTE's programs are "grounded in sound reasoning" and based on "rational evaluation of the Company's costs, revenues, and services, and ensure the equitable recovery of costs."[539]

DTE's defense of its DG proposal is unavailing because it is unsupported and circular. Witness Foley did not actually present any evidence to address Mr. Jester's or the Ann Arbor witnesses' assertions that the program is discriminatory and anti-competitive. Instead, witness

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[536] Foley Revised Rebuttal, 6 TR 1208.

[537] *Id.* at 1204.

[538] *Id.* at 1204-05.

[539] *Id.* at 1208.

Foley relies entirely on the argument that there is a cost shift from DG to non-DG customers to justify requiring DG customers to take service on a different rate. But he failed to rebut CEO witness Lucas's testimony that there is no actual cost shift. Witness Lucas demonstrated that there is no material cost shift resulting from Rider 18 customers reducing their own bill without "driv[ing] any cost savings related to the distribution system"[540] because non-Rider 18 customers would pay only "about $0.15 per year or $0.0125 per month for the supposed delivery revenue shortfall."[541] Meanwhile, DTE did not consider "potential cost reduction from lower usage during key hours that drive costs on the system[,]"[542] and did not even quantify the supposed cost shift from Rider 18 to non-DG customers or the "supposed cost-shift between DPV customers and non-DPV customers."[543] Witness Foley also admitted on cross examination that the Company has "not quantified the impact to non-DG customers" of the "amount that a DG customer on average reduces the amount they contribute towards the distribution system" and that the Company does not have a systematic way of looking at cost shifts.[544]

DTE also opposes MNSC's recommendation to conduct and provide a DG-specific cost of service analysis in its next rate case. Witness Foley argues that because MNSC did not recommend treating DG as a separate COS class, it is unclear what the objective of the study would be and what parameters and assumptions would be used.[545] Mr. Foley also claims it is unclear whether the proposed study intends to treat all DG Customers as a single class – which "would be inconsistent with the Company's current COS approach since it would comingle customers that

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[540] Lucas Revised Direct, 8 TR 3606 (quoting Foley Direct at 60).

[541] *Id.* at 3608.

[542] *Id.* at 3607.

[543] *Id.* at 3610; 3607.

[544] Foley Cross, 6 TR 1238-39.

[545] Foley Revised Rebuttal, 6 TR 1211.

are currently treated separately"[546] – or create multiple new COS classes. Finally, Mr. Foley argues that the proposed study is unnecessary because DTE already assessed cost impacts of customers installing DG – and this resulted in a cost shift.[547]

The Commission should reject DTE's arguments against MNSC's proposed study for multiple reasons. First, MCL 460.6a(14) requires the DG tariff to reflect equitable cost of service; therefore, the Commission should not approve a DG program tariff without demonstrating that it "reflect[s] equitable cost of service for utility revenue requirements . . . ."[548] DTE cannot demonstrate that its proposed tariff meets this requirement without performing a cost-of-service analysis for DG customers. As such, a cost-of-service analysis is clearly necessary. Second, witness Jester did not recommend treating DG customers as a separate class, and such treatment is unnecessary to perform MNSC's proposed study. The cost of service for any individual customer or subgroup of customers can be can be estimated without needing to go through a full cost-of-service study.[549] Third, witness Foley's assertion that the study is unnecessary because "DG customers are able to reduce the amount they contribute toward the distribution system without the Company being able to realize a similar level of savings"[550] fails because DTE's cost of service study does not allocate distribution costs per customer. Instead, the study allocates distribution cost based on contribution to annual peak load at voltage-level peak, and Mr. Foley did not provide any analysis showing that the amount DG customers pay in the tariff is less than the cost of service for those customers as allocated in the cost-of-service study.[551] Finally, DTE's arguments are

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[546] *Id.* at 1212.

[547] *Id.*

[548] MCL 460.6a(14).

[549] See for example, Case No. U-20471, February 20, 2020, Order, p. 87.

[550] Foley Revised Rebuttal, 6 TR 1212.

[551] Jester Direct, 8 TR 3817.

unavailing because, at their core, they are based on the incorrect assumption that there is a cost shift. DTE did not convincingly rebut witness Lucas's evidence that there is no material cost shift from DG to non-DG customers; therefore, any argument that the Company has already conclusively determined the cost impacts of DG is flawed.

3. DG Outflow Issues: DTE's proposal to reduce bill compensation for outflow credits to LMP should also be rejected because DTE treats outflow as negative load and the outflow has capacity value.

MNSC also encourages the Commission to reject DTE's proposal because "for purposes of transmission charges to DTE from MISO and for purposes of compliance with MISO's resource adequacy standards, DTE Electric treats outflow as 'negative load'."[552] Instead, MNSC recommends that DTE should "change the outflow credit from production cost less transmission cost to full production cost applicable in the customer's tariff at the time of the outflow."[553] Staff witness Revere, CEO witness Lucas, and GLREA witness Richter similarly recommended that the outflow compensation account for transmission.[554] Multiple parties including Staff, the CEOs, EIB, GLREA, and DAAO also recommended that the Commission reject DTE's outflow proposal "on the basis that outflowed energy has capacity value that should be paid to Rider 18 customers."[555]

In response, witness Foley implies that MNSC's recommendation to include transmission in outflow compensation is foreclosed by the Commission's Order in Case No. U-20162, in which the Commission "agree[d] with the ALJ's recommendation to adopt the Staff's proposal to

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[552] Jester Direct, 8 TR 3857-8.

[553] *Id.* at 2857.

[554] Revere Direct, 8 TR 5140; Lucas Revised Direct, 8 TR 3645 ("DPV outflow provides transmission benefits and should be compensated appropriately."); Richter Direct, 8 TR 3251.

[555] Foley Revised Rebuttal, 6 TR 1213.

calculate the outflow credit based on power supply less transmission."[556] He also asserts that "there is likely little or no transmission savings associated with DG outflow," and finally that "including the transmission component of Power Supply in the Rider 18 outflow credit would appear to be in direct conflict with MCL 460.1177(4)."[557] Regarding capacity value, Mr. Foley argues that, among other reasons, because the "current Rider 18 outflow compensation . . . represents a clear overcompensation for that outflow[,]" the outflow credit should be based on LMP adjusted for avoided line losses (which he claims "is equal to the near-term cost savings that the Company is able to realize from that outflow.").[558]

The Commission should reject witness Foley's arguments against including transmission in the outflow credit because they are based on an incorrect interpretation of the Commission's Order in Case No. U-20162, do not disprove transmission savings, and attempt to relitigate the Commission's holding in Case No. U-20162 regarding the applicability of MCL 460.1177(4) to outflow methodology.

In Case No. U-20162, "the Commission agree[d] with the ALJ's recommendation to adopt **the Staff's proposal** to calculate the outflow credit based on power supply less transmission" – the ALJ stated that it was supported by the record in that specific case.[559] In the instant case, Staff instead recommends including the transmission component of power supply because, similar to what witness Jester argued, outflow reduces the use of transmission.[560] Further, MNSC presented evidence of transmission savings: "Each kWh of outflow from customers with distributed generation in the peak hour of the month reduces the kW of transmission services for which DTE

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[556] *Id.* at 1223 (quoting Case No. U-20162, May 2, 2019, Order, p. 180).

[557] Foley Revised Rebuttal, 6 TR 1223.

[558] *Id.* at 1219-21.

[559] Case No. U-20162, May 2, 2019, Order, p. 180 (emphasis added).

[560] Revere Direct, 8 TR 5140-41.

Electric pays by that outflow adjusted for line losses."[561] DTE did not actually rebut this evidence because it only argued that reduction in 12CP demand will not impact *fixed* transmission costs.[562] Staff also acknowledged that "even including transmission rates as part of outflow likely does not fully encompass the contribution outflow has towards reducing the use of transmission."[563]

Further, Mr. Foley's argument that MCL 460.1177(4) prohibits including transmission in the Rider 18 outflow credit is at odds with the Commission's holding in Case No. U-20162 on that issue. In that Order, the Commission agreed "with the ALJ's findings of fact and conclusions of law regarding the inapplicability of MCL 460.1177(4) as it relates to this inflow/outflow methodology and the statutory charge for the Commission to establish a tariff reflecting equitable COS for DG customers."[564] The ALJ in that case noted that "the Commission has determined that the outflow credit could be an amount other than those defined in MCL 460.1177(4)(a) or (b)."[565]

Finally, MNSC agrees that an appropriate capacity credit should be included in the outflow credit and disagrees that this credit is a "clear overcompensation." DTE enjoys significant benefits from DG customers' outflow because

> [e]ach kWh of outflow from customers with distributed generation during the peak load hour that is used to determine DTE Electric's resource adequacy obligations reduces the resources that DTE Electric must provide by a kW adjusted upward for line losses, plus the planning reserve margin that MISO applies to peak demand to determine resource obligations.[566]

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[561] Jester Direct, 8 TR 3858.

[562] Foley Revised Rebuttal, 6 TR 1223.

[563] Revere Direct, 8 TR 5141.

[564] Case No. U-20162, May 2, 2019, Order, p. 180.

[565] Case No. U-20162, PFD, p. 273.

[566] Jester Direct, 8 TR 3858.

4. DG Program Design Issues: DTE's objection to MNSC witness Jester's comments regarding the DG program "cap" or lack thereof is misplaced because the proposed successor programs are not acceptable replacements for a fair DG tariff.

In his critique of DTE's DG program, MNSC witness Jester explained that the DG "cap" is actually the utility's minimum obligation to "accept distributed generation customers under a specified set of terms."[567] MCL 460.1173 does not "cap" DG overall. Instead, the Commission may "determine appropriate treatment for distributed generation once the 'cap' is exceeded."[568] DTE provides no reason to disregard Mr. Jester's critique of the DG program design. Instead of specifically addressing Mr. Jester's comments, DTE witness Foley generally objects to all Staff and intervenor testimony that he characterizes as recommending that the Commission establish a successor tariff to the Rider 18 on the grounds that Riders 14 and 5 "will allow DG customers to continue to interconnect their systems once the category-specific reservations established through MCL 460.1173(3) are met."[569] As a preliminary matter, witness Jester did not specifically call for a successor tariff. Instead, he demonstrated that because DTE is already obligated to provide a tariff for DG above the DG tariff cap, there is no need for the Commission to accept an unreasonable tariff in return for DTE going beyond the cap.[570] Even so, neither of DTE's proposed successor riders are acceptable. Both Riders 5 and 14 pay only approximately marginal cost of energy (LMP) for outflow.[571] Mr. Jester demonstrated that DTE avoids transmission and capacity costs as a result of outflow. These Riders therefore undercompensate DG customers.[572]

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[567] *Id.* at 3855.

[568] *Id.*

[569] Foley Direct, 6 TR 1231.

[570] Jester Direct, 8 TR 3855.

[571] Foley Direct, 6 TR 1174; Foley Revised Rebuttal, 6 TR 1232.

[572] Jester Direct, 8 TR 3857-8.

5. DG Section conclusion

DTE is requesting the Commission to accept an unjust bargain that will deter participation in its DG program and unduly discriminates against behind-the-meter solar generators, who are PURPA QFs. The Commission should reject proposed rate schedule D1.12, or reject DTE's proposed requirement for new DG customers to take service on schedule D1.12 if the Commission approves it. Additionally, the Commission should reject DTE's proposal to reduce Rider 18 bill credits for outflow to LMP and "require instead that they be equal to production cost portion of the customer's underlying inflow rate schedule at the time of outflow, including transmission costs."[573]

IX. PILOT PROGRAMS

A. Hydrogen Fuel System Pilot Program

In their hydrogen fuel system pilot project proposal ("hydrogen pilot"), DTE Electric is requesting inclusion in rate base of $19.011 million in capital expenditures toward building an electrolyzer that would produce hydrogen to be used as fuel at Blue Water Energy Center (BWEC), a new combined cycle methane gas plant. This $19.011 million is only a fraction of the $44.6 million total capital cost of the hydrogen pilot and includes $17.401 million in test year expenditures plus $1.611 million in bridge period funding.[574] The hydrogen pilot would be built throughout 2023 and 2024 and the Company estimates it would produce enough hydrogen to enable the Company to blend up to 5 percent hydrogen in the fuel combusted by BWEC.[575]

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[573] *Id.* at 3862.

[574] Ex. A-12, Sch B5.1, p. 2, line 30.

[575] MSNC believe the following portions of the record are relevant to this issue:

- Direct Testimony of Justin L. Morren, 5 659-671; Rebuttal Testimony of Justin L. Morren, 5 TR 741-743;

MSNC, along with Staff and AG, believe cost recovery for the hydrogen pilot should be disallowed. The Company claims the hydrogen pilot is needed to better understand hydrogen production, and that it would be 100% renewable or "green."[576] However, the record clearly demonstrates that the hydrogen pilot is a very costly experiment with minimal benefits, and the Company has not shown nor guaranteed that the hydrogen would actually be "green" – i.e., that production would be powered by 100% zero-carbon sources. Overall, the goals DTE is proposing to accomplish, namely exploring hydrogen in ways that are consistent with a "cleaner energy future"[577] and claiming its stake in a potential future hydrogen market, are unsupported. The Company failed to respond to these concerns in its rebuttal testimony, addressing neither the costliness of the hydrogen pilot, nor providing any assurance that it would be using fully renewable sources to produce the hydrogen. In short, the Company has not justified why the burden should fall on its customers to fund such a costly experiment.

1. The Hydrogen Pilot Program is Costly with Minimal Impacts

While the Company claims this pilot program would allow for *up to* 5% hydrogen blending, such level of blending would occur only sporadically throughout the use of the pilot program. In fact, the actual amount of fuel the Company is projecting to come from the pilot can best be described as de minimis.[578] As MNSC witness Comings illustrated, the hydrogen pilot would

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- Direct Testimony of Tyler Comings, 8 TR 4079-4084;
- Direct Testimony of Sebastian Coppola, 8 TR 4780-4793;
- Direct Testimony of John Richter, 8 TR 3240-3248;
- Direct Testimony of Jonathan J. DeCooman, 8 TR 5308-19; and
- Exhibit MEC-113.

[576] Morren Direct, 5 TR 659-60.

[577] Morren Rebuttal, 5 TR 743.

[578] Comings Direct, 8 TR 4080.

produce only 0.06 to 0.2% of BWEC's annual fuel.[579] Not only would the hydrogen pilot produce less than a percent of overall fuel at BWEC, the estimated cost for producing hydrogen ($14.79/mmBtu) is over four times the cost of gas ($3.40/mmBtu).[580] The Company is proposing this hydrogen pilot that would cost customers tens of millions of dollars and produce very little fuel in return. The Company has failed to provide any showing that hydrogen would be cost effective in the future,[581] nor has it identified a cost at which it believes the hydrogen pilot would be economically viable.[582] The Commission should deny rate recovery on the hydrogen pilot based on this unjustified cost alone.

2. There is No Guarantee that the Hydrogen Pilot Program will be 100% Green

The Commission should also deny rate recovery because DTE has failed to demonstrate that the hydrogen pilot program would, in fact, be "green." The Company has claimed that the electrolyzer would be powered by "100% renewable energy," which would make the hydrogen produced "green."[583] The Company has also cited hydrogen as a "a zero-carbon fuel."[584] The Company, by calling hydrogen "green", makes it seem that the whole hydrogen pilot would be zero-carbon. As a key part of their reasoning for exploring hydrogen, the Company has stated: "any expanded use of carbon-free energy would support a cleaner future."[585] However, just

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[579] *Id*.

[580] Coppola Direct, 8 TR 4785. While the Company stated in discovery that it had not developed the costs for generating hydrogen through the pilot (Comings Direct, 8 TR 4081), Attorney General witness Coppola estimated a cost of $14.79/MMBtu based on a total operating cost of $470,000 ($120,000 of O&M 10 expense and $350,000 in power supply costs for the hydrogen plant to operate) and the displacement of 31,776 MMBtu of natural gas ($470,000/31,776 MMBtu = $14.79/MMBtu).

[581] Coppola Direct, 8 TR 4784.

[582] Comings Direct, 8 TR 4081.

[583] Morren Direct, 5 TR 659.

[584] Morren Direct, 5 TR 660.

[585] Exhibit MEC-113.

because hydrogen does not produce carbon when *combusted*, does not mean the means of *producing* the hydrogen will be zero-carbon. Without clear assurance that the electrolyzer would be fully powered by zero-carbon energy sources, the combustion of hydrogen at a gas plant such as BWEC would simply shift the carbon emissions from the fuel combustion to the fuel production stage. As such, the stated objective of the hydrogen pilot – developing technology to advance carbon reduction goals – cannot be met.

The Company has failed to provide any such assurance. The Company claims that the electrolyzer will be powered by "excess renewables" that would otherwise be curtailed/not generated.[586] However, when asked about their experience with these excess renewables and whether they could provide an estimate, the Company could not provide information, stating that excess renewables were "minimal" in 2021 and while "curtailed intermittent renewable resources are possible in the future . . . . [t]he timing and amount of these excess resources cannot be accurately judged at this time."[587] Since DTE does not track these excess renewables, nor can it estimate how much they would use, the Company's claims that the electrolyzer will be powered by these excess renewables is unsupported.

When asked what would happen if the Company did not have enough excess renewables to power the electrolyzer, the Company stated it would "purchase "MIREC accounted renewable sources."[588] However, as MNSC witness Comings points out, by using MIREC sources – which are credits for energy that was produced under Michigan's renewable portfolio standard that ended in 2021 – there is a real risk that the hydrogen produced could be carbon intensive.[589] Not only has

[586] Comings Direct, 8 TR 4082.

[587] *Id*.

[588] Morren Direct, 5 TR 660-61.

[589] Comings Direct, 8 TR 4083.

the Company failed to show the production of hydrogen will be zero-carbon, it runs the risk of being reliant on carbon to power the electrolyzer, directly inconsistent with its decarbonization goals and claims that the hydrogen pilot would propel carbon-free energy.

The Company has not addressed the issue of whether the production of hydrogen will be truly green in its rebuttal testimony, despite witness Comings raising concerns. The Company does not expand on its reliance on curtailed renewables or explain how it will use MIREC energy sources. In fact, in its rebuttal testimony, the Company no longer even refers to its hydrogen pilot as "green", suggesting that the Company itself may not know if they can back up their claims around hydrogen.[590] As such, the hydrogen pilot would not only be costly to customers, but appears to not even fulfill its stated goal of advancing Michigan's decarbonization trajectory.

3. The Company Has Not Demonstrated a Need for this Hydrogen Pilot Program

The Company has neither performed an assessment of the need for the project, nor did it quantify whether it would be a net benefit to ratepayers. The Company has also stated that its has have not "conducted an analysis of the extent to which green hydrogen may be needed for the achievement of the Company's future carbon reduction goals."[591]

The Company expresses interest in a hydrogen pilot because "a pilot project is the innovative step forward that is needed if the hydrogen economy that is widely spoken of is to become reality."[592] However, as the Company has noted, other utilities have been exploring hydrogen, some through grant-funded projects.[593] The hydrogen pilot that DTE is suggesting has not been fully developed or assessed in terms of need and impact to ratepayers. The Company

[590] Morren Rebuttal, 5 TR 741-43.

[591] Comings Direct, 8 TR 4082.

[592] Morren Rebuttal, 5 TR 743.

[593] Morren Direct, 5 TR 663. The Company has not pursued non-utility funding for this pilot project (Comings Direct, 8 TR 4082).

claims that they need to test out hydrogen in order to have a large "experience level with hydrogen production and storage".[594] If the Company wishes to experiment with hydrogen, it can use its own resources, or seek out federal grants, which it has not yet done.[595] The Company should not be conducting a costly experiment at the expense of its ratepayers.

4. Conclusion of this Section

The Company has expressed interest in hydrogen production technology because it "seems poised to play a large part in a cleaner energy future."[596] However, this pilot program is not the route to do so, as it is costly experiment with very little impact on the actual fuel usage, with no guarantee that the hydrogen will be produced through fully renewable sources. Thus, the Commission should reject the hydrogen pilot proposal and disallow costs associated with it.

B. Strategic and Service Underground Pilot[597]

The Company proposes two Strategic Underground pilots: the Appoline pilot, which is about complete, and the Fairmount project. The Company projects approximately $54.3 million during the 2022 through the 2023 bridge and projected test-year periods. Witness Pfeuffer

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[594] Morren Rebuttal, 5 TR 743.

[595] Exhibit MEC-113.

[596] Morren Rebuttal, 5 TR 743.

[597] The record regarding the Company's Strategic Underground Pilots consists of the following:

- Pfeuffer Direct, 4 TR 336-345;
- Pfeuffer Rebuttal, 4 TR 437-450;
- Ex A-12, Sch B5.4, p. 10, line 47;
- Ex A-23, Sch M1, pp. 343-351 of 568, Sec. 11.6;
- Ozar Direct, 8 TR 4016-4022;
- Exs MEC-102, 103;
- Evans Direct, 8 TR 5429-32;
- Coppola Direct, 8 TR 4762-64;
- Ex AG-1.7; and
- Smith Direct, 8 TR 3118-21.

supported the Company's proposed investment in direct testimony and rebuttal.[598] Staff, the Attorney General, MNSC, and the Utility Workers Union of America, AFL-CIO, Local 223 Underground Lines Division addressed the pilots in direct testimony. MNSC witness Ozar raised concerns about the excessive cost of the pilots.[599] He also raised concerns about compliance with Rule 460.56, which allows lines to be converted to underground at fair cost.[600] Mr. Ozar testified that this is another spending proposal that raises application of "proactive" replacement rather than replacement upon failure or imminent failure – a theme discussed above.[601] Finally, Mr. Ozar recommended that the Commission reduce spending on the basis that the record is insufficient and premature to approve the pilot.[602] In particular, Mr. Ozar recommended the Company demonstrate the cost effectiveness of undergrounding laterals and services on a life-cycle basis, evaluate existing data resources to assess cost effectiveness, work with customers on a targeted tree contact issue to enhance trimming along service lines, consider efficiencies that may be achieved with corded water, sewer and street work, explore outside funding for piloting a project of this nature, and consider the experience and data of other utilities. Mr. Ozar recommended the Commission approve $1 million for this work.

In rebuttal to Mr. Ozar, Ms. Pfeuffer agrees that benchmarking is useful, and that it will continue to do so and to share its results with Staff.[603] Two responses are warranted. First, the recommendation is to support funding requests with benchmarking and other data. Sharing results with Staff, but not including them in the record in this case, is not responsive to Mr. Ozar's

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598 Pfeuffer Direct, 4 TR 336-44.

599 Ozar Direct, 8 TR 4016-18.

600 *Id.* at 4018-19.

601 *Id.* at 4019.

602 *Id.* at 4019-22.

603 Pfeuffer Rebuttal, 4 TR 449.

testimony. Second, the benchmarking that the Company has done so far does not include lifecycle cost assessments related to strategic undergrounding,[604] and therefore it is further not responsive to Mr. Ozar's testimony.

Next, Ms. Pfueffer notes that the Appoline project is nearly complete and the Company learned a lot from this pilot and its other benchmarking work, but now it is ready "to take the next steps" by proceeding to the next pilots.[605] This again is not responsive to Mr. Ozar's testimony. If the Company learned a lot about undergrounding, that would inform a lifecycle cost assessment, which has not been undertaken. Internalizing the learnings does not assist the Commission nor ratepayers in ensuring the project is reasonable, prudent, and cost effective. The Company misunderstands its obligation to document the lessons to be learned and the costs and savings associated with them. [CITE – distribution pilots order].

Finally, Ms. Pfeuffer indicates that she expects costs reductions by increasing the volume of work and lessons learned from Appoline and benchmarking.[606] Apparently the basis for expected cost reductions are founded in cost reductions achieved when the hardening program ramped up.[607] This is circular reasoning. The Company has proposed a high-cost pilot for the test year, with insufficient supporting data. It is premature in this proceeding to support the cost-effectiveness of the pilot by relying on cost savings that may be achieved when this pilot is subsequently rolled out more widely. The issue is whether this pilot is cost effective and whether the lessons expected to be learned are worth the very high cost. Concluding that the later roll-out of the pilot may be more cost effective (more efficient) than the pilot is circular and evasive.

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[604] Ex MEC-103.

[605] Pfeuffer Rebuttal, 4 TR 449.

[606] Pfeuffer Rebuttal, 4 TR 450.

[607] Ex MEC-102.

The Company failed to address Mr. Ozar's testimony regarding Rule 460.56, the Company's tendency towards proactive rather than preemptive replacements, the evidence that on a life-cycle basis undergrounding is not cost-effective. The Company also failed to address Mr. Ozar's recommendations for additional scope of assessment, alternative funding sources, revised programs to address the root cause of outages (enhanced trimming along secondary lines). For these reasons and those addressed by Mr. Ozar in his testimony, the Commission should reject the Company's proposed spending proposal and instead adopt Mr. Ozar's recommendations and with $1 million to that end.

In response to the direct testimony of Mr. Smith, who provides safety data associated with underground lines,[608] MNSC concurs that safety considerations should be part of a comprehensive and transparent (*i.e.*, provided in the rate case) workable cost/benefit analysis that demonstrates with reasonable confidence that undergrounding provides reliability and safety benefits on a lifecycle basis.[609] In other words, proper consideration of safety and reliability benefits would be best achieved with full review of the costs of retroactive undergrounding relative to all the benefits, on a lifecycle basis.

C. Charging Forward Expansion

1. The Charging Forward pilot proposal should be approved with modifications and the Commission should direct DTE to propose a permanent program by March 2023.

The Company proposes to extend its existing Charging Forward activities and to establish seven new programs: Residential Charging as a Service (CaaS), Commercial CaaS, Charging Hubs

[608] Smith Direct, 8 TR 3119-3121.

[609] See Case No. 20645, Feb. 4, 2021, Order, p. 10 ("[Q]uantification of expected benefits is essential for the Commission to consider in reviewing pilot program proposals through the ratemaking process.").

for fleet vehicles, rebates for transit bus batteries, vehicle rebates for income-qualified customers and rideshare drivers, and an emerging technology fund.[610]

MSNC strongly support extending and expanding Charging Forward. The program portfolio is consistent with the Commission's guidance for customer-funded EV programs, it is broadly supported by the parties, and the programs are critical to address core barriers to EV adoption. MNSC urge the Commission to approve the Charging Forward program with four modifications:

- The existing **Direct Current Fast Charging (DCFC) program** should support 350kW charging capacity at new make-ready locations and rebate recipients should be required to install stations capable of 150kW charging to meet EV drivers' current and future needs;
- The new **Residential CaaS program** should require participants to take service on a time-of-use electricity rate;
- The new **income-eligible and transportation network company EV Rebates** should be available at the point-of-sale; and
- The new **Charging Hubs program** should include creating capacity maps for charging that are shared online to facilitate similar investments by non-utility market participants.

In addition, the Commission should direct DTE to take two steps to make EV infrastructure investments part of the normal course of utility business: first, to report basic data on the net effects of EV adoption and charging; and second, to propose a permanent EV program within approximately four months of the conclusion of this case. Though DTE has agreed to begin transitioning to permanent programs, it resists providing basic data related to EV charging. The

[610] Direct Testimony of Benjamin Burns, 7 TR 2413-84. MNSC believes the following portions of the record are relevant to these issues: Burns Rebuttal, 7 TR 23XX-2501; Rebuttal Testimony of Sharon G. Pfeuffer, 4 TR 530-35; Direct and Rebuttal Testimony of Douglas Jester, 8 TR 3820-40, 4114A-H ; Direct and Rebuttal Testimony of Alan Freeman, 8 TR 5533-50; Rebuttal Testimony of Kevin Krause, 8 TR 5510A-J; Rebuttal Testimony of Nicholas Revere, 8I TR 5152-5155; Direct Testimony of Dr. Laura Sherman, 8 TR 4370-91; Direct and Rebuttal Testimony of Matthew Deal, 8 TR 4560-4621; Direct and Rebuttal Testimony of Carine Dumit, 8 TR 4677-4712; Direct Testimony of Margarita Parra, 8 TR 3551-59; Direct Testimony of Adarka, 8 TR 4624-28; Rebuttal Testimony of Thomas Ashley, 8 TR 4715-29.

Commission should require DTE to furnish this information and it should direct DTE to file a permanent program, consistent with its Order in U-20963 directing Consumers to file a permanent EV program.[611]

a. The Charging Forward proposal is consistent with the Commission's EV policy.

In Case No. U-18368, the PSC adopted "high-level principles" for EV-related utility programs.[612] Recognizing "transportation electrification is in the public interest" and "electric companies are uniquely suited" to address its barriers, the Commission invited utilities to develop EV programs.[613] The Commission identified four broad topics for EV programs (infrastructure, rate design, grid impacts, and customer education), but also emphasized that "flexibility, creativity, and transparency are […] key drivers to success here" and that "this order is intended to provide focus for potential pilot programs" and "not prescriptive guidelines."[614]

"[W]hen evaluating … pilot programs for Commission approval," the Commission's Order stated that it would consider data collection and reporting, load management, and the inclusion of new technologies.[615] Since issuing its guidance the Commission has approved several EV programs, including the first phase of the Charging Forward program.[616] That decision emphasized

[611] Case No. U-20963, Dec. 22, 2021, Order, pp. 311-312.

[612] Case No. U-18368, Dec. 20, 2017, Order, p. 34 ("[T]he Commission finds the guiding principles set forth by the broad coalition of stakeholders in this docket to be reasonable and appropriate. Based on the comments submitted and the adoption of these high-level principles, the Commission finds that a second collaborative technical conference, targeted at further exploration of potential pilot programs to be initiated by regulated utilities, as possible deliverables, will be most beneficial to all at this time.").

[613] *Id.* at 12, 35.

[614] *Id.* at 35-36.

[615] *Id*.

[616] See, e.g., Case No. U-20697, Dec. 17, 2020, Order, pp. 239-40 (approving Consumers' PowerMIFleet program); Case No. U-20134, Jan. 9, 2019, Order Approving Settlement Agreement, pp. 4-5 (approving Consumers' PowerMIDrive program); Case No. U-20162, May 2, 2019, Order, p. 113 (approving DTE's

the importance of "test[ing] new and novel practices and technologies."[617] The PSC also stressed that EV programs must "serve double-duty by directly addressing core barriers (such as range anxiety), and by enabling the company to learn reasonable and practicable ways to actively manage charging times and locations."[618] The Commission's prior decisions on EV programs also underscore the need to get EVs to scale, correctly observing that "none of [the many benefits of EVs] will materialize until EV chargers become more prevalent and accessible."[619]

As with Charging Forward's first phase, the pilot expansion is well-aligned with the Commission's EV program guidance. The new and existing infrastructure programs would support charging station deployment in market segments that are critical for passenger EV adoption. Travel corridors and long-dwell locations are the highest value public locations, and expanded support for home charging (single- and multi-family) will improve charging access in a location that is a "virtual necessity for EV ownership."[620] Not only are these key market segments, but infrastructure gaps are present in each. The Charging Hubs program will similarly meet a critical need for fleet vehicles, supporting a transition to electric technologies for fleet operators.

Several of the new programs test creative new approaches. The Residential CaaS, Commercial CaaS, and Transit Bus programs would utilize innovative financing mechanisms, helping customers overcome upfront price premiums for charging stations and batteries. The vehicle rebate programs for income-qualified and rideshare drivers would promote equity in EV ownership, helping would-be EV drivers overcome a core barrier to EV adoption. And the purpose

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Charging Forward program); Case No. U-20359, Jan. 23, 2020, Order Approving Settlement Agreement, pp. 4-5 (approving Indiana-Michigan Power's IMPluggedIn program).

[617] Case No. U-20162, May 2, 2019, Order, p. 113.

[618] *Id.*

[619] Case No. U-20134, Jan. 9, 2019, Order, p. 8.

[620] Jester Direct, 8 TR 3826.

of the Emerging Technology Fund is to test new and novel practices. While Charging Forward can and should be improved with MNSC's recommended modifications, the proposed programs are clearly consistent with the Commission's guidance.

b. <u>The Commission should direct DTE to modify four of its Charging Forward programs.</u>

(i) <u>The DCFC program should support charging at power levels that meet EV drivers' current and future charging needs.</u>

The Commission should require DTE to set minimum charging levels for fast charging sites supported by its make-ready investments and charging station rebates. Specifically, make-ready infrastructure should support up to 350 kW fast charging stations, and rebate recipients should install DCFC capable of at least 150 kW charging.

Make-ready support for 350 kW fast charging would future-proof sites, allowing for easy future expansion. And a minimum of 150 kW at newly deployed stations would deliver an improved driver experience: most new EVs support 150kW charging, and faster charging supports lower cost charging because a given charging service can be provided with fewer ports and lower overall installation cost.[621] These standards also make good policy sense. DTE jointly administers its fast-charging program with the State's Charge Up Michigan program, which relies on a State siting study that recommends these power levels.[622] These power levels are also consistent with the FHWA's guidance for the National EV Infrastructure (NEVI) Program.[623]

DTE disagrees, arguing that the market should decide what fast charging stations to install and that future-proofing its make-ready investments is contrary to its "normal process [for] requesting a service upgrade [when customers need additional capacity]."[624] Neither argument is

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[621] Jester Direct, 8 TR 3822-23.

[622] *Id.*

[623] *Id.*

[624] Burns Rebuttal, 7 TR 2519.

availing. It is entirely proper for DTE to set minimum standards, particularly where they further the central goals of the program to establish a durable infrastructure backbone and to accelerate EV adoption. That mission is not served by installing yesterday's technology or building sites that are not readily expandable in a growing EV market. DTE's plan to underinvest today and retrofit tomorrow is inappropriate for this customer funded program and is at odds with the Commission's direction in U-20134 for utilities to "think proactively" in designing EV programs to "avoid reactive and expensive capital investments in the future."[625]

(ii) *The Residential Charging as a Service program should require participating customers to take service on a time-of-use rate.*

MNSC strongly support expanding support for charging at the home—the location where access to charging is a "virtual necessity" for EV adoption. However, the terms of this program should be modified to require participating customers to take service on a time-of-use (TOU) rate. This would harmonize the program terms with DTE's residential rebate program and leverage the grid integration potential at the home. As witness Jester explains, "Home is where vehicles are parked for the most hours of the day, making the most convenient place to charge, especially overnight when people are sleeping and there is plenty of spare capacity in the grid."[626]

Despite the ease of managing home charging and efficacy of TOU rates, DTE maintains that Residential CaaS participants should not be subject to any terms for charging to provide "transparency into customers that would participate if not for that requirement."[627] But that is not a useful data point. And gathering it will come at the expense of creating system wide efficiencies from grid integrated charging that will benefit all ratepayers. DTE seems to assume that requiring

[625] Case No. U-20134, Jan. 9, 2019, Order, p. 8.

[626] Jester Direct, 8 TR 3826-27.

[627] Burns Rebuttal, 7 TR 2512.

service on a TOU rate will hamper participants' flexibility to charge when they want, but that is a false assumption: a TOU rate is an incentive, not a mandate. And in any event the home is where charging behavior is most easily adapted to grid conditions. It is critical to continue to foster good charging behavior as EVs become more prevalent. In prior cases the Commission has stressed the need for utility programs "to ensure that new load associated with EV charging maximizes net benefits,"[628] and to make "more efficient use of excess generation and distribution capacity."[629] The Commission should direct DTE to do the same with this program by requiring participants to take service on a time-of-use rate.

(iii) The EV vehicle rebates should be available at the point of purchase.

To fully serve those qualifying customers that wish to purchase an EV, the rebate should be available at the point of sale rather than as rebate to be applied for and paid after the vehicle purchase. A vehicle purchase is not a minor transaction, and the promise of a rebate is unlikely to help most in need in the same manner as an upfront incentive. In approving a similar EV rebate program for Xcel Energy, the Colorado Public Utilities Commission recognized the "significant challenge the up-front cost of EVs poses to income-qualified customers, including the difficulty of qualifying for, and the delayed timing of, the existing state EV tax credit" and approved the program as a point-of-sale rebate.[630] The Commission should do the same here.

(iv) The Charging Hubs program should include sharing online charging capacity maps that will facilitate similar investments by non-utility market participants.

With Charging Hubs, DTE proposes to own and operate fast charging stations for fleet operators and to facilitate electrification of their vehicle fleets. In testimony, DTE justifies its

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628 Case No. U-20162, May 2, 2019, Order, p. 113.

629 Case No. U-20134, Jan. 9, 2019, Order, p. 8.

630 See Jester Direct, 8 TR 3829-31 (citing to Colorado Public Utilities Commission order approving Xcel Energy's EV Rebate program).

Charging Hubs proposal by claiming "DTE is uniquely suited to site Charging Hubs where there is both sufficient power supply and customer demand," and "because DTE can identify ideal locations on its system, it can deploy Charging Hubs at a minimum total cost."[631] But in response to discovery, DTE was unable or unwilling to identify locations meeting its criteria, raising a concern that DTE may be withholding the information for competitive advantage.[632] More generally, access to this information will be increasingly important as EV adoption rises and the need for DCFC increases.[633]

To improve transparency and foster a sustainable market for EV technology providers, the Commission should require DTE to share the information it will use to site its charging hubs via online capacity maps. In rebuttal, DTE contends that preparing such maps would be too burdensome (even though DTE already publishes similar maps) and that developers of fast charging stations may access such information through direct conversation with DTE as part of a specific interconnection request.[634] But to require developers to guess at good locations for specific projects and ask DTE for interconnection studies is a cumbersome and inefficient approach. It would discourage thoughtful planning and delay the development of the very infrastructure that DTE's program is designed to increase demand for. The Commission should either direct that this capacity information be made available to potential hosts and developers of DCFC or, alternatively, the Commission should direct DTE to implement the program using third party hosts and providers solicited via an RFP rather than owning and operating its own charging stations.[635]

[631] Burns Direct, 7 TR 2443.

[632] Jester Direct, 8 TR 3828.

[633] *Id.*

[634] Direct Testimony of Sharon G. Pfeuffer 4 TR 530-35.

[635] Jester Rebuttal, 8 TR 4114H.

c. <u>The Commission should direct the Company to transition to permanent EV programs and to report data on the net effects of EV charging.</u>

MNSC recommend that the Commission take two steps to integrate EV charging into the normal course of utility business. First, the Commission should direct DTE to propose a permanent program by March 15, 2023. This directive would be consistent with the Commission's decision in U-20963, which directs Consumers Energy to "present a plan for a permanent [EV] program in the next general electric rate case."[636] Transitioning to a permanent program is also prudent in light of forecasted EV adoption rates and related infrastructure needs. While DTE has indicated in testimony that it plans to propose permanent programs in its next rate-case,[637] MNSC are concerned that the "scale of the Charging Foward program proposed by DTE is insufficient to meet EV charging infrastructure needs in its territory through 2025. "638 MNSC also urge the Commission to adopt the following guidance for DTE's permanent program, presented here in summary form and discussed in detail in the testimony of MNSC witness Mr. Jester:

- The permanent program should not be subject to a fixed budget cap, but rather it should be responsive to EV adoption and customer interest;
- The permanent program should be structured similar to line extensions, such that non-participating customers are no worse off than if EV adoption was not occurring, with revenue from electricity consumption for EV charging used for additional investment to accelerate EV adoption or contributing to fixed costs thereby diluting rates; and
- The permanent program should aim to address DTE's share of the goal in MI Healthy Climate Plan goal to provide EV charging infrastructure for 2 million EVs statewide by 2030.[639]

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636 Case No. U-20963, Dec. 22, 2021, Order, pp. 311-312.

637 Burns Rebuttal, 7 TR 2506 ("[T]he Company proposes beginning to introduce permanent offerings, as applicable, starting with its next rate case.").

638 Jester Direct, 8 TR 3823.

639 Jester Direct, 8 TR 3836-40.

The Commission should also direct the Company to report data on the net effects of EV adoption and charging in the Company's service territory. Specifically, the Commission should require DTE to report the following basic data, which the Minnesota Public Utilities Commission requires electric utilities in that state to report annually:

> 1) numbers of electric vehicles by class registered in the utility's service territory, 2) amounts of electricity delivered for EV charging by customer rate schedule where the charging occurs, 3) revenue from electricity delivered for EV charging by customer rate schedule where the charging occurs, 4) costs of power supply for EV charging by rate schedule, 5) gross margin from EV charging by rate schedule, 6) revenue requirements related to EV infrastructure and allocation of revenue requirements by customer rate schedule, and 7) net margin benefitting customers in each rate schedule."[640]

This data would support a full analysis of the revenue from EV charging in DTE's service territory and aid review of permanent program filing. DTE claims it is unable to reliably calculate many of these specific data points, but identical data is routinely supplied by DTE's sister utilities, and the Commission should direct DTE to do the same in its next rate-case.

X. FUTURE RATE CASES, FURTHER STUDY, OTHER ISSUES

A. Tree Trimming Variable Cycle Pilot

As discussed above in the **Adjusted New Operating Income** section, Mr. Ozar also recommended a pilot program to test variable cycle tree trimming, based on circuit tree density and other factors.[641] The Company's current 5-year cycle goal may be refined to provide additional cost-effective reliability benefits. Mr. Ozar recommended that the Commission require the

[640] *Id.* at 3840; see also Direct Testimony of Laura Sherman, 6 TR 3663-64, Case No. U-20963 (describing and quoting the Minnesota Public Utilities Commission decision from which these metrics are derived).

[641] See Section III, Adjusted Net Operating Income, Projected Tree Trim Expense discussion above. See also Ozar Direct, 8 TR 4030-34.

Company to immediately initiate a pilot to test such an optimization approach for trimming based on circuit characteristics, and to file a report detailing the results, both in terms of reliability benefits and cost savings. The Company declined to rebut this recommendation, so the Commission should adopt it.

B. Proposed Pilot Program for Electrifying Propane, Fuel Oil & Kerosene Heated Homes[642]

1. Introduction

MNSC witness Chris Neme has proposed that DTE work with stakeholders to develop a residential pilot program for electrifying propane, fuel oil, and kerosene-heated homes in DTE's service territory and bring the pilot program for Commission approval within a year of a Commission order in this proceeding.[643] Because Mr. Neme's testimony describing the pilot is unrebutted, MNSC respectfully requests that the Commission approve the proposal as described in MNSC witness Neme's direct testimony without modification.

a. Description of Proposal

Witness Neme recommends that while DTE and interested stakeholders should develop the program design details, the pilot DTE proposes to the Commission should have the "principal purpose" to "test how to drive significant demand for cold climate heat pumps and identify and address the market delivery challenges what will arise when there is such demand."[644] The pilot design should also be consistent with the following five principles[645]:

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

- Direct Testimony of Chris Neme (8 TR 4085-114); and
- Exhibits MEC-74, MEC-75, MEC-76, and MEC-77.

[643] Neme Direct, 8 TR 4092-3.

[644] *Id.* at 4113.

[645] *Id.* at 4113-4.

1. Addressing at least both space and water heating, and potentially cooking fuel and other fossil fuel end uses as well.
2. Having "a goal of electrifying at least 3,000 homes over three years."[646]
3. "[E]nsuring that at least 33% of the electrified homes are low-income."[647]
4. Committing "to pay 100% of the cost of electrification measures for the low-income participants"[648]; and
5. Emphasizing and supporting investment in building envelope efficiency improvements, potentially by referring participants to EWR program offerings and/or supplementing those offerings "to ensure significant follow through on insulation and air sealing opportunities."[649]

b. <u>Adopting MNSC's proposal is a cost-effective, low-risk way to address a critical component of tackling the climate crisis that currently faces market barriers to adoption.</u>

Witness Neme presented substantial evidence that electrification of fossil fuel heated homes is essential reducing greenhouse gas emissions by 2050 to at or near net-zero, the level "necessary to stabilize the global climate."[650] He also demonstrated that cold climate heat pumps are an energy efficient and cost effective way to "fuel-switch to electricity provided by a decarbonized grid."[651] Space and water heating are typically the first and second highest residential energy end uses in climates like Michigan, and together "account for more than 90% of propane

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[646] *Id.* at 4113.

[647] *Id.*

[648] *Id.* at 4114.

[649] *Id.*

[650] *Id.* at 4093. See also *id.* at 4093-4 (citing studies from Princeton University and Massachusetts gas utilities on building electrification as a decarbonization strategy).

[651] Neme Direct, 8 TR 4093; 8 TR 4096-8 (providing evidence of heat pump cost and efficiency versus propane).

and other fossil fuels energy used in homes."[652] The MI Healthy Climate Plan also recognizes the importance of building electrification as a decarbonization strategy,[653] and DTE's own "analysis also states that increased reliance on electric heat pumps 'align(s) with long-term decarbonization goals in the state.'"[654] However, there are significant market barriers to adoption of electrification measures such as cold-climate heat pumps, including customer awareness and cost of the technology.[655] As such, electrifying existing building stock using heat pumps could take decades without additional initiatives, and this slow pace is compounded by the fact that electrification fossil heating cannot be addressed through DTE's EWR programs.[656] DTE should therefore design and implement a pilot program to drive demand for heat pumps and lower their cost.

In addition to the climate benefits of electrification, replacing fossil heating with cold climate heat pumps will ultimately save customers money. Witness Neme demonstrated that propane customers would have an annual cost savings of 49% by making this switch.[657] Savings for those customers, who are disproportionately low income, are likely to be even greater in the future based on the forecasted cost of that fuel.[658] The Company also "concluded in a recent

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[652] *Id.* at 4094-5.

[653] *Id.* at 4095.

[654] *Id.* at 4094 (quoting Guidehouse and DTE, *Residential Heat Pump Breakeven Analysis*, presentation to the Michigan EWR Collaborative, Mar. 15, 2022, slide 7).

[655] Neme Direct, 8 TR 4110.

[656] *Id.* at 4092, 4110-11.

[657] *Id.* at 4098. Mr. Neme also noted that while his analysis does not include the impacts of cooling costs, "adding cooling effects to the analysis would improve the average customer economics of electrification." *Id.* at 4100.

[658] *Id.* at 4102.

analysis that centrally-ducted cold climate heat pumps have both lower annual operating costs and lower lifecycle costs than homes with oil or propane furnaces."[659]

Finally, the large differences between DTE's proposed electric rates and actual marginal cost of serving additional electric load means that electrification can actually help lower rates by offsetting program costs through increased net revenue.[660] Witness Neme calculated that an electrification program with a significant emphasis on electrifying low-income homes "could result in an increase in net revenue in excess of $3 million per 1000 electrified homes over the life of the heat pumps – or ~$10 million for 3000 electrified homes."[661]

c. <u>Conclusion</u>

MNSC's proposed residential propane electrification pilot program will enable DTE to work towards making changes that, as the MI Health Climate plan describes, "are imperative – that must happen, **and happen now** to meet our goals."[662] As such, MNSC encourage the Commission to instruct DTE to develop this uncontroversial and cost-effective pilot program following the guidelines in Mr. Neme's testimony.

C. Proposed Pilot for Continuous Distribution System Monitoring[663]

The Company's plan to significantly increase distribution capital investment to replacing its aging assets and improve grid reliability. The spending ramp up, manifested in this case,

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[659] *Id.* at 4095-96.

[660] *Id.* at 4104.

[661] *Id.*

[662] *Id.* at 4112 (quoting MI Healthy Climate Plan, p. 27).

[663] The record on this issue consists of the following:

- Ozar Direct, 8 TR 4023-29;
- Exs MEC-16, 17, 18, 104; and
- Pfeuffer Rebuttal, 4 TR 536.

indicates the Company and customers would benefit from more tools that improve reliability and lessen the urgency for replacement.[664] MNSC witness Ozar recommended the Company initiate a new pilot program for an instantaneous distribution system monitoring system to supplement its field inspections.

Mr. Ozar testified regarding the need and potential value of additional distribution system monitoring to enhance observational capabilities to identify incipient adverse conditions that may result in fault during the significant periods between asset evaluations.[665] While the Company has several inspection and line sensor programs, it has no continuous asset condition monitoring system or capability. For example, its poles and pole tops are ten-year assessment cycle, and its asset replacement plan is substantially driven by life-cycle age and condition data. The importance of continuous monitoring is that faults (failures, outages) occur in the interim periods between inspections; unlike periodic inspections, continuous monitoring instantaneously identifies incipient conditions that could result in future outages. The proactive characteristic of fault anticipation monitoring stands in stark contrast to the Company's periodic inspection paradigm.

Mr. Ozar described one continuous monitoring system called *Distribution Fault Anticipation (DFA)*, which uses a device installed in a substation, together with system software, to identify events along distribution circuit that persist ahead of an outage, but which conventional technology ignores.[666] DFA analyzes wave-forms and sends messages back to a master station server in real-time.[667] The sensing data comes from conventional equipment; it does not require deployment of line sensors or communication with line reclosers or other line devices.[668]

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[664] Ozar Direct, 8 TR 4022.

[665] Ex MEC-18 (defining the concept of incipient faults); Ozar Direct, 8 TR 4023-24.

[666] Ozar Direct, 8 TR 4025-28; Exs MEC-16, 18.

[667] Ex MEC-16, p. 4.

[668] *Id.*, p. 3.

The technology may detect underlying conditions upstream that cause outages downstream, thus providing the opportunity for proactive and comprehensive repairs by getting to the root cause. DFA technology has also been shown to improve safety conditions by avoiding down lines and fire hazards. DFA technology is also able to determine the precise location along long rural distribution lines (*e.g.*, tree branch hanging on a line or broken insulators), which increases the efficiency of service restoration. The utility serving Austin, Texas, piloted DFA technology in 2016 to improve predictive fault analysis, with the aim of anticipating issues associated with voltage/current waveforms, fault location, wire downs, conductor-slap, equipment arcing and explosions, and trees and vegetation. DFA technology has the potential to substantially improve reliability and to reduce reliability spending by refining line replacement and rehabilitation based on precise fault causation data; proactive repairs are more economical, safe, and better for customers than waiting for failures.

Mr. Ozar testified that it would befit the Company and its ratepayers to integrate a concerted fault anticipation technology pilot into its repertoire of technology investments, and he recommended that DTE fully investigate the potential for application to DTE's system.[669] He recommended that the Company file a report on its investigation within six months in this docket. The report should include, among others the Company may identify, the DFA technology, provide a thorough cost and benefit analysis, and include at least one pilot project proposal to test integration. Given the magnitude of *Infrastructure Resilience and Hardening* spending, which the Company is plans to continue in future rate cases, it is critically important to immediately invest in the implementation of continuous monitoring to identify incipient conditions.

In response to Mr. Ozar's recommendation, Ms. Pfueffer testified as follows:

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[669] Ozar Direct, 8 TR 4029.

> The Company is very interested in machine learning, understands the benefits, is exploring deploying this technology, and has begun investigating machine learning. Since this work is underway, the Commission does not need to direct the Company to undertake a machine learning pilot.[670]

In discovery following this rebuttal testimony, the Company identified four "machine learning" technologies that the Company has begun investigating.[671] This includes a regression model that uses weather and historic outages to forecast outage events; a rule-based model that analyzes AMI voltage intervals to identify voltage issues; a prioritization model to identify high risk circuits; and a model to predict EV trends. The Company identified additional technology and automation it is exploring in Section 12 of the DGP.[672] In discovery, the Company stated that it reviews technology "driven by the need to serve customers and not by technology trends in isolation."[673] Then the Company explained that it opposes the suggestion to file a report related to its technology efforts and it will not undertake a pilot to investigate and test continuous distribution monitoring technology.

A few responses are warranted. First, none of the modeling efforts identified replicate DFA, which is a device installed at the substation to detect incipient faults along the circuits in real time, and often ahead of an outage event. Second, Mr. Ozar's recommendation to explore DFA is not a "technology trend" that is proposed "in isolation." It is developed technology with a proven track record to cost-effectively improve reliability. DTE has a track record of poor reliability,[674] an uncharacteristically long circuit inspection cycle (10 years, compared to 4-5 year industry

[670] Pfeuffer Rebuttal, 4 TR 536.

[671] Ex MEC-104.

[672] Ex A-23, Sch M1, pp.360-441 of 568.

[673] Ex MEC-104, p. 2.

[674] Jester Direct, 8 TR 3779-84.

average cycles),[675] and it is proposing huge spending increases to replace equipment that is not a substantial contributor to outages (*i.e.*, wooden crossarms and obsolete pole top equipment[676]). Exploring technology at the intersection of each of those considerations – targeted at the worst circuits to improve reliability without unnecessary replacements – is smart and necessary.

Third, if the Company believes that the technology it is already exploring is the same as continuous monitoring that is capable of detecting upstream root cause faults before they are otherwise manifested as downstream events, then it should share its explorations and insights into that technology with the Commission and stakeholders. In Chapter 12 of the 2021 DGP, the Company identifies various technology investments, but it is not evident that any of them achieve what DFA has been proven to achieve.[677] If DTE contends that ratepayers are already funding an investigation into continuous monitoring and fault identification to preemptively address outages before they occur, it should identify the investment and report the details of its evaluation of the technology so the Commission and stakeholders may evaluate those findings.

The Commission should recognize that DFA has the potential to reduce outages, improve safety, and reduce costs. Investigating DFA, and whatever other continuous monitoring system the Company may identify, is a reasonable next step. Since it has not yet been demonstrated how DFA (and other similar technology) work on DTE's distribution system, the Company should initiate a pilot to test the technology. The Commission should adopt Mr. Ozar's recommendation and require the Company to investigate and report back in this docket in 6 months with a cost and benefit assessment and at least pilot project proposal to test integration.

[675] Ex MEC-33 (benchmarking says 4-5 year inspection cycle); see Ozar Direct, 8 TR 3997-98 (recommending shorter inspection cycles).

[676] Ozar Direct, 8 TR 3980-81, 3995; Ex MEC-19.

[677] Ex A-23, Sch. M1, pp. 360-441 of 568.

D. Distribution System Planning Modifications

Although the Company filed its 2021 Distribution Grid Plan (DGP) in Case No. U-20147, this is the first general rate case where the Company presented the DGP to support distribution system investments. MNSC witness Jester reviewed the DGP in the context of proposed distribution spending in this proceeding, as well as in the context of overall affordability for residential ratepayers. Based on his review, as well as his participation in numerous prior Commission proceedings and meetings and his expertise in Michigan electric utility regulation, he offered a series of recommendations to improve distribution system grid planning going forward. Also foundational to Mr. Jester's recommendations related to distribution planning modifications was his discussion about the role of trees and the cost-effectiveness of tree trimming, which is summarized above in the section on Adjusted Net Operating Income, related to tree trimming expense.

Company witness Pfeuffer filed rebuttal testimony regarding some of Mr. Jester's recommendations, which are addressed in full below. Regarding the issues where there was no rebuttal, in the interest of judicial efficiency and preserving Commission and ALJ resources, MNSC presents a summary of Mr. Jester's recommendations. MNSC requests that the Commission adopt all of Mr. Jester's recommendations because they are reasonable, well-supported, and would facilitate cost-effective distribution system planning going forward.

First, Mr. Jester recommended that the Commission require DTE in its next distribution plan to consider equitable reliability in prioritizing DTE Electric's distribution system spending.[678] He explained that harms resulting from outages may be relatively more significant in low-income areas, so DTE should prioritize outage harm reduction where there are concentrations of low-

[678] Jester Direct, 8 TR 3811-13.

income households. DTE has already started to incorporate environmental justice into its Global Prioritization Model, and the Commission should urge completion.

Ms. Pfeuffer responded to Mr. Jester's recommendations, together with related recommendations related to environmental justice and equity by other witnesses.[679] She states the Company identified potential planning process changes, including to GPM processes, to incorporate environmental justice considerations.[680] The Company committed to incorporate an EJ plan in its next GDP or rate case. The Company intends to rely on the MI EJ tool once it is available, though she identified challenges with the tool. Given the Company's commitment, and the work already done, the Commission should adopt Mr. Jester's recommendations, including the recommendation that the next plan iteration be filed in September 2023, to include a plan to prioritization outage harm reduction in areas with concentrations of low-income homes.

Second, Mr. Jester recommended that the Commission require DTE in its next distribution plan to develop an approach to managing EV charging that schedules charging in consideration of local distribution system considerations and incorporates opportunities provided by vehicle-to-home technologies.[681] The Company recognizes the potential impacts of increasing volumes of electric vehicles and also distributed resources (behind-the-meter solar and storage) in DTE's territory, and its distribution system plans should analyze and reflect the opportunities to use managed charging to avoid distribution system constraints and take advantage of bidirectional power flows. The Commission may also direct Staff to convene stakeholders to make recommendations on general policy and expectations in this regard.

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[679] Pfeuffer Direct, 4 TR 505-21.

[680] *Id.*, at 516.

[681] *Id.*, 3813-14.

Third, Mr. Jester recommended that DTE should replace its assessment of asset health based largely on age statistics with one more thoroughly based in reliability and repair theory.[682] DTE justifies billions of dollars of spending on statistics (average age, expected life) that do not support asset replacement. He supported an alternative approach based on actual historic failure rates and equipment condition (based on inspections) to develop expected current rate of requirement and replacement. This analysis should be incorporated into depreciation rates, spending plans, and effects on reliability.

In rebuttal, Ms. Pfeuffer agreed with Mr. Jester's support for a distribution system asset replacement approach based on asset condition rather than asset age, and claims the Company has adopted that approach.[683] In support, Ms. Pfeuffer referred to Chapter 8 of the 2021 DGP.[684] Section 8 of the DGP describes the Company's approach to "asset health assessment" for 20 asset classes in the distribution system.[685] This is a circular response: Mr. Jester specifically reviewed Chapter 8 and testified to its flaws.[686] His recommendation to adopt a maintenance approach based on equipment condition supported by inspections is in opposition to the Company's age-based approach described in Chapter 8. Mr. Jester explained why average age compared to expected life, nor percentage whose age is greater than expected life, are necessarily meaningful as to equipment condition. He further noted that equipment condition is likely impacted by the location – such as where there are dense tree areas leading to frequent broken and spliced conductors, and lightly-loaded transformers versus heavily-load transformers. Chapter 8 begins with a chart identify the average age and life expectancy of each of the 20 subclasses and discusses for each subcategory

[682] *Id.*, 3814-15.

[683] Pfueffer Rebuttal, 4 TR 535.

[684] *Id.*, citing Ex A-23, Sch M1, Section 8.

[685] Ex A-23, Sch. M1, pp. 159-218 of 568.

[686] Jester Direct, 8 TR 3805-3808.

the average age of the assets, the age distribution of the equipment, the average failure age, and typical maintenance issues with the equipment. Of the 20 subcategories, 15 are part of the Company's "proactive replacement program," which drive substantial spending proposals.[687] For example, the pole and pole top hardware subcategory (subsection 8.8) anticipates $430 million of "proactive replacement" from 2021 to 2025.[688] Mr. Ozar specifically opposed the "proactive" (versus preemptive) capital replacement approach to pole top equipment that the Company is proposing.[689] Ms. Pfeuffer's rebuttal does not address the concerns raised by Mr. Jester and expounded by Mr. Ozar.

Fourth, Mr. Jester recommended that DTE should optimize monitoring and inspection programs to support equipment replacement based on conditions indicating incipient failure.[690] Calibrated increased inspection frequency to allow the detection and repair or replacement of incipient failures before they fail would be more cost effective than replacing components because they are old. Mr. Jester recommended that DTE's next rate case or grid plan demonstrate, for each category of distribution assets (substations, conductors, underground equipment, poles and poletops) that the frequency, specifications, tracking, and prioritization of monitoring and inspections are optimized relative to the cost for repair/replacement upon failure.

Fifth, Mr. Jester supported the Company's recognize the need for local load data and forecasts to support distribution system investments by location.[691] To transition to electric transportation, electric heat, and distributed generation in a cost-effective way, DTE must have the ability to adequately forecast load locally.

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[687] Ex A-23, Sch. M1, p. 161.

[688] *Id.* at p. 161.

[689] Ozar Direct, 8 TR 3960-67, 3985-98.

[690] Jester Direct, 8 TR 3815-16.

[691] *Id.*, 3816-17.

Sixth, Mr. Jester recommended that the Commission revisit distribution system cost allocation based on engineering practices, particularly focused on the allocation of costs by time.[692] DTE was unable or unwilling in this proceeding to provide load profiles at the substation level in the distribution system. This data would assist in understanding the timing and contributions of each class to local demand on substations and circuits. He recommended the Commission require DTE to file 8760-hour load profiles for each substation or circuit as supplemental data in the next rate case and to examine distribution system cost causation in the next grid plan.

In rebuttal, Ms. Pfeuffer indicated the Company is evaluating the feasibility of using AMI data to produce the bottom-up hourly generation system load forecast, referencing page 69 of the DGP. Thus, the Company will likely be in a position to meet Mr. Jester's recommendation that it file the 8760-hour load profiles for its distribution substations in the next rate case, and examine distribution system cost causation in its next DGP.[693]

Seventh, Mr. Jester recommended that the Company include the rate impact of each category of spending and for the plan as a whole as part of its next DGP.[694] While the Company outlines various spending proposals in the DGP, the Commission and interested parties are unable to assess the rate impact of particular spending on a comparable basis because rate impacts vary by depreciation rates, operations and maintenance expense, and other considerations. Mr. Jester recommended the Company present in its next DGP all elements of the plan with illustrative required revenue calculations, and display the effects on customers through rate impacts. Presenting that information in the DGP (as opposed in a rate case) will aid examination of the plan as a whole.

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[692] Jester Direct, 8 TR 3817-18.

[693] Jester Direct, 8 TR 3819.

[694] *Id.*, 3819.

Eighth, and finally, Mr. Jester recommended that the Commission should direct DTE and other utilities to proceed to a next round of distribution system planning and direct the specific improvements to be addressed in the next iteration.[695] He recommended the Commission require the Company to file its next update in approximately September 2023.

The Company is proposing significant and increasing distribution system investments, which are driving substantial rate increases in this case and in the future, particularly for residential and secondary commercial customers. Those rates are already high compared to peer utilities.[696] Distribution planning still remains less vigorous than necessary to ensure cost-effective distribution investments. Mr. Jester's recommendations are reasonable and would improve distribution planning to address root cause reliability issues, increase transparency, and ensure value for ratepayers. The Commission should adopt his recommendations.

E. Affordability Assessment – Comparative Cost Allocation Assessment[697]

MNSC witness Jester recommended that the Commission should consider DTE's overall performance across a variety of metrics and conclude that DTE has failed to support its request for an increased ROE to 10.25.%.[698] Referencing the Company's high residential rates relative to other states and utilities, Mr. Jester offered potential explanations may include the Company's cost allocation approach.[699] To further evaluate the causes of Michigan's high residential rates,

[695] *Id.*, 3819-20.

[696] Jester Direct, 8 TR 3789-92.

[697] MNSC believes the record related to this issue consists of the following:

- Jester Direct, 8 TR -3797-3800;
- Crozier Rebuttal, 7 TR 2382-84; and
- Revere Rebuttal, 8 TR 5158-60.

[698] Jester Direct, 8 TR 3796-97.

[699] *Id.* at 3797-99.

particularly distribution investments that are driving high and rising residential rates, Mr. Jester recommended that the Commission and Staff, with advice and review from stakeholders, develop the data and analysis to evaluate in a later docket a comparison of other utility cost allocations.[700]

Witnesses for DTE Electric and Staff opposed the recommendation to assess the role of cost allocation to high residential rates through an assessment of how other utilities approach cost allocation.[701] While this issue is foundational to the reasonableness of the Company's cost allocation approach, MNSC recognizes that the Company and Staff are have limited resources to undertake a comparative assessment of other utilities at this time. Without conceding the importance of such an assessment, MNSC is not pursuing this recommendation further in this proceeding.

F. Value of Reliability[702]

In response to the Company's discussion of the Interruption Cost Estimator (ICE) developed by the Lawrence Berkeley National Laboratory, MNSC witness Ozar addressed the limitations of available tools to evaluate the economic efficiency and public interest of distribution investments.[703] In particular, Mr. Ozar noted that the ICE calculator is stale and not based on Michigan specific data. It has limited usefulness to justify the cost effectiveness of reliability investments, as well as the prudency of the rate of replacement of aging infrastructure. Mr. Ozar

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[700] *Id.* at 3799-3800.

[701] Crozier Rebuttal, 7 TR 2383; Revere Rebuttal, 8 TR 5159-60.

[702] MNSC believes the record related to this issue consists of the following:

- Pfeuffer Direct, 4 TR 281-82, 285-86;
- Pfueffer Rebuttal, 4 TR 513-14, 535;
- Ex A-23, Sch M8;
- Coppola Direct, 8 TR 4774-78;
- Ozar Direct, 8 TR 4038-40; and
- Koeppel Rebuttal, 8 TR 4360-67.

[703] Ozar Direct, 8 TR 4038-39.

recommended that the Commission initiate a process to develop an updated, Michigan-specific interruption cost analysis. Mr. Ozar further recommended that the Company develop a survey to customers to gather Michigan-specific interruption cost data. Attorney General witness Coppola raised similar concerns about the LBNL calculator.[704]

In rebuttal, Company witness Pfeuffer indicated the that Company is in the process of partnering with LBNL to update the ICE study, including with state-specific data.[705] Soulardarity supported Mr. Ozar's recommendation to initiate a workgroup and develop a value of reliability analysis, he opposed Mr. Ozar's suggestion a Michigan-specific analysis should incorporate a "customer willingness to pay" perspective.[706]

MNSC support the position of Soulardarity and We Want Green Too. The Commission should initiate a workgroup to progress the development of an up-to-date, Michigan specific assessment of the economic impacts associated with outages on a locational basis. This should include a survey of customers who have suffered outages, to gather accurate, local interruption cost data. To the extent DTE is working with LBNL to update the national ICE calculator, that does not moot the recommendations in this rate case to survey its DTE customers who have experienced outages and convene a workgroup for the specific purpose of considering a value of reliability assessment for Michigan. This is an issue best addressed in a workgroup, rather than awaiting the next rate case to assess whether whatever "regional, state-specific update" to the ICE calculator LBNL develops will satisfy the issues raised by Mr. Ozar, Mr. Coppola, and Mr. Koeppel.

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[704] Coppola Direct, 8 TR 4776.

[705] Pfeuffer Rebuttal, 6 TR 514, 535.

[706] Koeppel Rebuttal, 8 TR 4361-64.

XI. STAFF & INTERVENER REBUTTAL OF EACH OTHER

The Disputed Issues Chart circulated by the Company in this case identifies a series of issues where Staff and Interveners addressed each other's testimony as opposed to Company testimony. MNSC has addressed those issues other parts of this brief.

XII. CONCLUSION AND RELIEF REQUESTED

For the reasons stated above, MNSC respectfully requests that the Commission:

A. Disallow inclusion in rate base of $15.248 million in avoidable or premature capital expenditures related to the Belle River plant;

B. Reject the Company's projections of capacity shortages for MISO Zone 7 in Planning Year 2025/2026, together with the economic analysis derived from the high capacity price scenarios and the arguments suggesting Belle River should not retire in PY 25/26 due to reliability concerns;

C. Disallow $745.726 million in unsupported and unreasonable distribution system capital expenditures for expanding the 4.8kV Hardening and Pole/PTMM programs and for the Strategic & Service Undergrounding pilot;

D. Reject the Company's proposal to increase the awarded ROE to 10.25% and instead reduce ROE to closer align with the lower estimated market-based cost of equity for DTE Electric;

E. Require DTE in its next rate case to support the capitalization of tree trimming and inspections associated with the 4.8kV hardening and the Pole/PTMM programs and the 80/20 split between installation and removal for capital inspections and trimming;

F. Direct DTE to adjust the Cost of Service Study to assign MERC fixed costs to fuel rather than to production plant and to assign fuel handling labor expense to fuel;

G. Approve the Company's proposed alternative D1.11 rate that applies a time-based rate to capacity and non-capacity power supply, and further require DTE in its next case to propose a time-based rate for distribution costs;

H. Reject the Company's proposed D1.12 Stable Bill rate;

I. Continue the Staff-led CIAC workgroup to address persistent flaws in the Company's current CIAC policies;

J. Reject DTE's proposed changes to the DG program and instead require that Rider 18 outflow bill credits be equal to the production cost at the time of outflow, inclusive of transmission costs, with direction for DTE to analyze the cost of service for behind-the-meter DG customers in its next rate case;

K. Reject inclusion in rate base of DTE projected $19.011 million of capital expenditures in the bridge and test year periods for the development of a hydrogen fuel system pilot program at the Blue Water Energy Center;

L. Approve the Company's proposed EV-related expansions with modifications proposed by MNSC to better align the program with Commission guiding principles for ratepayer EV investments;

M. Direct DTE to develop a variable cycle pilot as part of the enhanced tree trimming program and file a report documenting the results in terms of reliability benefits and cost savings;

N. Direct DTE to develop a pilot program for electrifying propane, fuel oil, and kerosene-heated homes in DTE's territory and bring the pilot to the Commission for approval within a year;

O. Direct DTE to develop a pilot for continuous distribution system monitoring to identify incipient adverse conditions in the distribution system;

P. Adopt a series of recommendations by MNSC witness Jester to improve distribution planning and order DTE to file an updated distribution plan in September 2023;

Q. Initiate a workgroup of Staff, stakeholders, and utilities to update and develop a Michigan-specific value of reliability study, which should first include a survey of DTE Electric customers who have experienced outages; and

R. Provide such other relief that is just and reasonable based on the record in this proceeding and the arguments presented in this brief.

MNSC reserves the right to request additional or different relief in reply to the positions expressed in the initial briefs of other parties.

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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.	U-20836

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 (Public Version)** 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.	U-20836

CONFIDENTIAL PROOF OF SERVICE

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

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Date: July 26, 2022

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