

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,  
for miscellaneous accounting authority

---

Case No. **U-21297**  
**(e-file paperless)**

**MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S  
CORRECTED INITIAL BRIEF**

Daniel E. Sonneveldt (P58222)  
Anna B. Stirling (P84919)  
Monica M. Stephens (P73782)  
Assistant Attorneys General  
Public Service Division  
7109 W. Saginaw Hwy., 3rd Floor  
Lansing, MI 48917  
Telephone: (517) 284-8140

**DATED: August 15, 2023**

## TABLE OF CONTENTS

	<u>Page</u>
I. Introduction.....	1
II. Revenue Deficiency .....	3
III. Rate Base.....	4
A. Staff recommends a total rate base of \$22,452,387,000. ....	5
1. Staff recommends a net utility plant of \$21,003,072,000. ....	5
a. Staff recommends a total utility plant of \$28,826,534,000. ....	5
b. Staff recommends an accumulated depreciation and amortization reserve of \$7,823,462,000. ....	5
2. Staff recommends net capital lease property of \$11,636,000. ....	5
3. Staff recommends net nuclear fuel property of \$201,880,000. ....	6
4. Staff recommends capital lease obligations of \$13,486,000. ....	6
5. Staff recommends a total working capital of \$1,249,285,000. ....	6
a. Staff recommends a \$7,257,549 reduction to working capital – other accounts receivable. ....	6
b. Staff recommends a \$1,680,000 reduction to working capital – move balances to 13-month averages.....	7
c. Staff recommends a \$900,000 reduction to working capital—regulatory asset—charging forward.....	7

d.	Staff recommends a \$658,000 reduction to working capital—regulatory asset—delivered fuel electrification pilot.....	8
B.	Staff recommends several reductions to the Company’s capital expenditures, along with some approvals.....	12
1.	The Commission should exclude \$178,970,203 from DTE’s projected production capital expenditures.....	13
a.	Staff recommends the capital spending associated with Steam Generation: Non-Routine Additions – Monroe Bottom Ash Conversion should be reduced by \$39,859,725. (Appendix E, Line 2.).....	13
b.	Staff recommends capital spending associated with Steam Generation: Routine – Monroe Units 3 and 4 should be reduced by \$48,717,728. (Appendix E, Line 22.).....	14
c.	Capital spending associated with Other—Non-Routine should be reduced by \$90,392,750. (Appendix E, Line 30.).....	17
i.	Capital spending associated with Blue Water Energy Center should be reduced by \$8,100,000. (Appendix E, Line 24.).....	17
ii.	Capital spending associated with Blackstart Project 1, 2, and 3 should be reduced by \$6,525,750. (Appendix E, Line 25-27.).....	19
iii.	Capital spending associated with Slocum Battery Project should be reduced by \$3,540,000. (Appendix E, Line 28.).....	21
iv.	Capital spending associated with 2025/2026 Battery should be reduced by \$72,227,000. (Appendix E, Line 29.).....	23
2.	The Commission should make adjustments due to the timing of the Fermi Generator Project.....	27

3.	The Commission should exclude \$245,732,000 from DTE’s projected distribution capital expenditures.....	27
	a. Capital spending associated with strategic capital program— City of Detroit Infrastructure Upgrades of \$172,298,000 should be disallowed. (Appendix E, Line 38.).....	28
	b. Capital spending associated with strategic capital programs should be reduced by \$69,592,000. (Appendix E, Line 39.).....	32
	c. Capital spending associated with Infrastructure Redesign and Modernization Pilot—Strategic and Service Undergrounding should be reduced by \$3,842,000. (Appendix E, Line 40.).....	35
4.	Staff recommends reducing demand side management capital expenditures by \$9,503,360.....	38
	a. Other Demand Response Programs and Pilots-- Battery Energy Storage.....	39
	b. DTE Insight Application.....	42
5.	The Commission should reduce the Company’s information technology capital expenditures by \$77,252,206.....	45
	a. Capital expenditures for Plant and Field IT should be reduced by \$836,213. (Appendix E, Line 52.).....	46
	b. Capital expenditures for Customer Service IT should be reduced by \$17,570,000. (Appendix E, Line 58.).....	50
	c. The Commission should disallow all capital costs requested for the Changing Bill Size project, representing a total of \$675,000, with \$548,250 in the bridge period and \$126,750 in the test year.....	53

d.	The Commission should disallow all capital costs requested for the Customer Service Sales & Service Project, representing \$5,494,500 for the test year.....	54
e.	Capital expenditures for Oracle Forecasting Tool should be reduced by \$3,800,000. (Appendix E, Line 60.).....	55
f.	Capital expenditures for Infrastructure Automation Maturity IT should be reduced by \$406,000. (Appendix E, Line 61.).....	56
g.	Capital expenditures for Infrastructure Operations Center Automation IT should be reduced by \$406,000. (Appendix E, Line 62.) .....	57
h.	Capital expenditures for Information Technology Level 2 Cost Estimates should be reduced by \$54,233,993. (Appendix E, Line 71.).....	58
6.	The Commission should reduce the Company’s corporate staff capital expenditures by \$1,341,667.....	62
7.	The Commission should reduce the Company’s charging forward capital expenditures by \$4,930,000.....	63
8.	The Commission should reduce the Company’s contingency capital expenditures by \$14,040,000.....	65
IV.	Capital Structure and Rate of Return.....	67
A.	Cost of Capital.....	67
B.	Capital Structure.....	68
C.	Return on Equity.....	69
D.	Discounted Cash Flow model (DCF).....	69

E.	Capital Asset Pricing Model (CAPM).....	70
F.	Risk Premium.....	72
G.	Other State Commission ROE Decisions.....	73
H.	Response to Dr. Villadsen’s rebuttal critique.....	73
V.	Net Operating Income.....	74
A.	Staff recommends an adjusted net operating income of \$959,795,000.....	74
1.	Staff recommends total operating revenues of \$5,113,378,000.....	75
a.	Staff recommends sales revenue of \$3,640,512,000.....	75
b.	Staff recommends base fuel and purchase power revenue of \$1,361,901,000.....	78
c.	Staff recommends other revenue and R2 of \$110,965,000.....	78
2.	Staff recommends total operating expenses of \$4,204,718,000 for the projected test year.....	78
a.	Staff recommends fuel and purchase power expense of \$1,361,901,000.....	79
b.	Staff recommends Other O&M expense of \$1,173,553,000.....	79
i.	Staff recommends reducing steam power generation O&M expense by \$6,723,000.....	80
ii.	Staff recommends reducing uncollectible expense by \$11,805,000.....	83
iii.	Staff recommends reducing regulated marking O&M expense by \$1,000,000.....	85

	vi.	Staff recommends reducing corporate support O&M expense by a total of \$98,922,000.....	86
	c.	Staff recommends reducing pension and benefits O&M expense by \$10,352,000.....	98
	d.	Staff recommends depreciation and amortization expense of \$1,146,233,000.....	103
	e.	Staff recommends property tax expense of \$320,250,000. ....	104
	f.	Staff recommends other tax expense of \$50,173,000.....	104
	g.	Staff recommends state and local income tax expense of \$74,106,000.....	104
	h.	Staff recommends federal income tax expense of \$77,225,000.....	104
	i.	Staff recommends other utility (income)/deductions of \$1,277,000.....	105
	j.	Staff recommends a total allowance for funds used during construction (AFUDC) operating income of \$54,114,000.....	105
	k.	Staff recommends loss on reacquired securities of \$2,980,000.....	106
	l.	Staff recommends tree trim surge program revenue deficiency of \$8,847,000.....	106
VI.		Cost of Service and Rate Design.....	107
	A.	The Commission should approve Staff's proposal to use the Class Peak method to allocate demand-related distribution plant costs for the secondary voltage level.....	107
	B.	The Commission should approve Staff's Capacity Revenue Requirement and SRM Capacity Charge.....	109

C.	The Commission should maintain the Company’s current residential customer charge.....	112
D.	Staff takes no issue with the Company’s allocation of the distribution related Infrastructure Recovery Mechanism (IRM) revenue requirement.....	113
E.	Staff’s proposed change in distribution cost allocation should be implemented over time.....	114
F.	Residential Rate Design.....	116
	1. Rate D1.7 should be designed to not produce a negative charge.....	116
	2. CEO’s regression analysis should not be used as the basis for any recommendations.....	117
	3. DAAO’s Payment Stability Pilot changes should be rejected...	119
G.	Commercial and Industrial Rate Design.....	120
	1. Power supply demand and energy charges for Rates D4, D11, and D6.2 should be set to their historical ratios.....;	120
	2. EIBC/IEI/United’s proposal to establish time-of-use TOU rates for primary and secondary customers should be rejected in part.....	124
	3. Rider 10 Administrative Charge.....	128
H.	Lighting Rate Design.....	130
	1. General lighting adjustment.....	130
	2. MI-MAUI lighting revenue requirement proposals.....	131
I.	Other Issues.....	132
	1. DAAO’s Payment Stability Pilot changes should be rejected.....	132

2.	Tariff implementation.....	133
3.	Other Tariffs.....	134
J.	Considerations for future rate cases.....	134
1.	The DG tariff should not compensate for societal benefits.....	135
2.	Incorporation of testimony by reference should not be permitted.....	136
3.	Rider 3 does not discriminate against PURPA QFs.....	136
4.	Bloom Energy’s Rider 3 proposals should be rejected.....	137
5.	Compensating Battery or Vehicle to Grid exports at full retail should be rejected.....	137
6.	The demand charge holiday should be extended and a rolling demand charge holiday should be implemented.....	138
7.	Demand charges for DC Fast charging send a price signal for reliability.....	139
8.	EV programs should be designed to maximize ratepayer benefits.....	140
9.	Permanent EV programs should support maximizing ratepayer benefits.....	140
10.	Staff recommends approval of submetering on rate D3 for customers on rate D4, but not for customers on other rates at this time.....	141
11.	Not all distribution upgrades for EV charging should be socialized.....	142
12.	Rate D3 provides reasonable flexibility for EV charging.....	143
13.	The Company’s proposed Community Charging tariff language should be rejected.....	143

VII.	Distributed Generation and Demand Response.....	143
	A. Staff Recommends the Company be directed to update Demand Response (DR) tariffs to clarify customer eligibility to participate with DR aggregators.....	143
	B. The Commission should reject the other DR tariff changes recommended by MEIBC.....	144
VIII.	IRM.....	146
IX.	Staff's Other Issues.....	149
	A. Ford MIGreenPower (MIPG) Contract.....	149
	B. The Commission and ALJ should encourage the Company to cease the sale of uncollectible accounts to third parties, and warn the Company that such sales, net of proceeds from same, will be removed from the calculation of uncollectible expense to be included in rates.....	151
	C. The ALJ should recommend, and the Commission should order, that the cost of the Company's EV programs be allocated based on revenues by class.....	153
	D. The Commission should order certain deprecated language regarding resale and EV charging be removed from the Company's tariffs.....	154
	E. Certain of MNSC witness Jester's claims and proposals related to rate comparisons should be rejected.....	154
	F. Claims that EV programs should return the full value of gross margin from incremental load should be rejected.....	155
	G. Ratepayers should not be responsible for all charging infrastructure.....	157
	H. MNSC witness Jester's unclear proposal regarding "revenues in excess of cost of service" should be rejected.....	158
	I. Charging delivery charges for delivery of energy is not a double charge.....	159

J.	The technical requirements for EV chargers proposed by MEIBC/IEI/AEU witness Sherman should be rejected.....	159
K.	Additional incentives for bidirectional chargers should be rejected at this time.....	160
L.	CEO witness Parra’s proposal related to Rider 21 should be rejected as unsupported.....	160
M.	Certain of EM witness Zakem’s proposals and claims related to the State Reliability Mechanism (SRM) and associated capacity charge/rates should be rejected.....	160
N.	Association of Businesses Advocating Tariff Equity (ABATE) witness James R. Dauphinais’ refund method for the proposed Earnings Sharing Refund Mechanism (ESRM) should be modified if approved.....	161
O.	Soulardarity and We Want Green, Too (collectively, the Detroit Area Advocacy Organizations or DAAO) witness Jackson Koepfel’s claim that the value of distributed generation (DG) is not captured by the current outflow credit should be rejected.....	163
P.	DAAO witness Koepfel’s proposal for low-to-moderate income (LMI) customer DG incentives should be rejected.....	164
Q.	DAAO witness Koepfel’s proposal that ratepayers fund the purchase of batteries for LMI customers should be rejected.....	164
R.	To the extent the Commission or ALJ considers the incorporation by reference of extensive testimony and exhibits from the records of other cases by DAAO witness Koepfel, the responsive testimony and exhibits to same should also be considered.....	164
S.	Certain claims and proposals made regarding standby rates by Bloom witnesses should be rejected.....	165
T.	Michigan Municipal Association for Utility Issues (MI-MAUI) witness Richard Bunch’s claim that uncollectible expense should not be allocated to streetlighting customers should be rejected.....	168
U.	Distribution Planning and Equity Related Issues.....	168

1. To support future environmental justice and equity analyses, Staff recommends the Commission request the Energy Affordability and Accessibility Collaborative define vulnerable community based on MIEJScreen composite scores and require future environmental justice analyses provide information in gradations based on these composite scores.....168
2. Staff revises its GIS data related recommendations in brief. Staff recommends the Commission require the Company, in future rate cases and distribution plans, provide data on interruption by zip code and census tract.....185
3. Staff recommends that known public safety hazards should be addressed according to adopted rules.....190
  - a. Statute and prior Commission orders require that the distribution system be maintained for the safety of the public.....190
  - b. Staff finds that arc wire could be removed at a faster pace, enhancing public safety.....191
  - c. Staff believes the 4.8kV system presents unique public safety hazards based on the historical injuries and fatalities reported to the Commission from 2013 to 2023.....194
  - d. Staff recommends future Company reports of third-party contacts reported under Rule 804, include additional information to the third party’s health status and contact description.....197
  - e. Staff finds that Company investments do not equally support vulnerable communities and non-vulnerable communities.....197
  - f. Staff recommends the Commission require the Company to provide greater transparency into why projects, programs, and deployment locations are selected in future rate cases.....200
  - g. Staff recommends the Commission require the Company include climate resiliency planning in future distribution plans, including a climate vulnerability assessment with

	50- and 100-year climate forecasts at a minimum and a climate resilience plan.....	204
h.	Staff recommends the Commission require the Company to develop a clear and repeatable process that allows interested parties to request, safely obtain, and use GIS data with different levels of detail for their own analyses.....	208
i.	Staff recommends the Commission require the Company to engage interested and affected parties in stakeholder meetings in future distribution plans.....	209
j.	Staff agrees with Ann Arbor and MI-MAUI that utilities should improve communications and coordination with local units of government when making capital investment plans.....	212
k.	Conclusion.....	215
l.	The Staff recommends the Company perform additional analysis on undergrounding.....	218
m.	Staff recommends damage prevention and MISS DIG improvements.....	219
n.	Nuclear Production Tax Credits.....	222
o.	Tree Trimming Recommendation.....	222
p.	Incorporation of testimony by reference should not be permitted.....	224
X	Conclusion.....	225

## I. Introduction

In its initial filing, the DTE Electric Company (“DTE” or “Company”) projects that it will experience a total electric revenue deficiency of \$618.536 million for the test year ending November 30, 2024 (Exhibit A-11, Schedule A1), alternatively Staff projects that DTE’s total electric revenue deficiency will be \$386.676 million.

(Appendix A.) The primary reasons for Staff’s lower projected revenue deficiency are Staff’s lower rate base, return on equity, and operating expenses. This is highlighted as:

- i. DTE’s projected total rate base is \$22.611 billion, while Staff’s total projected rate base is \$22.452 billion—\$158.843 million less than the Company’s. (Appendix B.) It is lower because Staff reduced the Company’s plant in service by \$428.261 million (including adjustments to production, nuclear, distribution, demand side management, information technology, corporate staff, charging forward, and contingency), increased construction work in progress (CWIP) by 257.628 million, increased the depreciation reserve (an offset to total utility plant) by \$22.287 million, and reduced working capital by \$10.496 million. (Appendix E.)
- ii. DTE’s proposed ROE is 10.25%. Staff’s recommended ROE is 9.8%. (Appendix D.) The intervening parties recommend ROE’s below 9.8%. Staff’s lower ROE reduces the Company’s projected revenue deficiency by about \$53.6 million. Staff’s recommended ROE differs from the Company’s by 45 basis points because Staff used several different ROE inputs.
- iii. DTE projects that its total company operating expenses will be \$4.316 billion, while Staff projects that it will be \$4.205 billion. Staff’s projection is \$111.431 million less than the Company projects. (Appendix C.) Staff’s proposed operating expenses are lower because Staff adjusted the Company’s Operation and Maintenance (O&M) expense by \$128.802 million to reduce, among other things, generation, uncollectibles, regulated marketing, corporate support, and pension and benefits expense.

Staff’s proposed disallowances are justified and well supported. Staff’s recommendations strike the right balance between DTE’s interests and its

ratepayers' interests. Public utilities are entitled to a reasonable opportunity to earn a reasonable rate of return on their investments, *ABATE v Public Service Comm*, 430 Mich 33, 39 (1988), just like ratepayers are entitled to just and reasonable rates. The just-and-reasonable-rate doctrine is “aimed at navigating the straits between gouging utility customers and confiscating utility property.” *Verizon Communications, Inc v FCC*, 535 US 467, 481 (2002). Staff's adjustments are well within these bounds.

Staff's objective is recommending “just and reasonable rates that are fair to both ratepayers and the company.” *In re Detroit Edison Co*, MPSC Case No. U-15244, 12/23/08 Opinion & Order, p 11. Although many of DTE's proposed rate increases are justified, many are not. In several instances, the Company has overreached by increasing its capital-expenditure and operating-expense projections beyond reasonable expectations. In other instances, the Company has ignored Commission precedent and asked to recover expenses that it has requested before and been repeatedly denied. Staff's adjustments correct these excesses.

In conclusion, DTE does not need a \$618.536 million rate increase. However, considering the significant capital investments in its future, an increase appears warranted. Staff proposes a \$386.676 million rate increase and a 9.8% ROE, which gives the Company a reasonable opportunity to earn a fair rate of return while giving ratepayers access to safe and reliable energy at reasonable rates.

## II. Revenue Deficiency

Staff initially projected a revenue deficiency of \$383.235 million, a revenue requirement decrease of \$235.301 million from the Company's originally filed revenue deficiency of \$618.536 million found on Exhibit A-11, Schedule A-1, Line 10. (7 TR 4588 - 4589.) The main factors driving Staff's overall adjustment are Staff's lower rate base, its higher net operating income, and its lower required rate of return. (*Id.*) In this brief, Staff has updated its case and now projects a revenue deficiency of \$386.676 million, a revenue requirement decrease of \$231.860 million from the Company's originally filed revenue deficiency of \$618.536 million. (Appendix A, Line 10.) A reconciliation of the updates Staff has made in this brief can be found on Appendix F, Lines 11-35.

The \$231.860 million difference between the Company's proposed total revenue deficiency of \$618.536 million and Staff's proposed total revenue deficiency of \$386.676 million is due to the following adjustments (revenue requirement impact in millions):

Rate Base	\$(11.3)
Rate of Return	(53.6)
Revenue	(0.5)
O&M	(128.8)
Depreciation	(22.7)
AFUDC	<u>(15.0)</u>
<b>Total Staff adjustments (rev. req. impact)</b>	<b>\$(231.9)<sup>1</sup></b>

---

<sup>1</sup> Appendix A, line 10; Calculations of impacts Appendix F, lines 3-9.

### **III. Rate Base**

“Rate base consists of the capital invested in utility plant, less accumulated depreciation [i.e., net plant], plus the utility’s working capital requirement.” *In re Detroit Edison’s 2010–2011 Rate Case*, MPSC Case No. U-16472, 10/20/2011 Order, p 5. In this case, rate base also includes net capital lease property, net nuclear fuel property, less: capital lease obligations.

#### **A. Staff recommends a total rate base of \$22,452,387,000.**

Staff recommends a total rate base of \$22,452,387,000, which is \$158,843,000 less than the Company’s initial projection of \$22,611,230,000. Staff’s rate base is \$158,843,000 lower than the Company’s because Staff adjusted the Company’s: 1) production; 2) nuclear; 3) distribution; 4) demand side management; 5) information technology; 6) corporate staff; 7) charging forward; and 8) contingency capital expenditures. (Appendix E.) Staff’s capital expenditure adjustments are detailed in Section III.B. Staff also adjusted working capital for: a) other accounts receivable; b) move balances to 13-month averages; c) regulatory asset—charging forward; and d) regulatory asset—delivered fuel electrification pilot (DFEP). (Appendix E.) Staff’s working capital adjustment is detailed in Section III.A.5.

#### **1. Staff recommends a net utility plant of \$21,003,072,000.**

The first component of rate base is net utility plant. Net utility plant consists of total utility plant minus accumulated depreciation and amortization. Staff’s recommended total net utility plant is \$21,003,072,000. (Appendix B, Line 8.)

Staff's proposed net utility plant is \$148.347 million lower than the Company's net utility plant of \$21.151 billion because of a \$428.261 million reduction to plant in service, a \$257.628 million increase to CWIP, and a \$22.287 million increase to accumulated depreciation and amortization. (Appendix B, Line 2, 4, 7, 8, column d; Appendix E, Line 90, Col. c, d, e.)

**a. Staff recommends a total utility plant of \$28,826,534,000.**

The first component of net utility plant is total utility plant. (Appendix B, Line 6, Col. e.) Staff recommends a total utility plant of \$28,826,534,000, which is \$170,634,000 less than the Company's initial projection of \$28,997,168,000. (See Section III. B below and Appendix E for the capital expenditure adjustments.)

**b. Staff recommends an accumulated depreciation and amortization reserve of \$7,823,462,000.**

The second component of net utility plant is the accumulated depreciation and amortization reserve. (Appendix B, Line 7, Col. e.) Staff recommends accumulated depreciation of \$7,823,462,000, which is \$22,287,000 more than the company's initial projection of \$7,845,749,000. (Section III. B and Appendix E.)

**2. Staff recommends net capital lease property of \$11,636,000.**

The second component of rate base is net capital lease property. Staff recommends the Administrative Law Judge (ALJ) and the Commission adopt the Company's projection of \$11,636,000. (Appendix B, Line 9, Col. e.)

**3. Staff recommends net nuclear fuel property of \$201,880,000.**

The third component of rate base is net nuclear fuel property. Staff recommends the ALJ and the Commission adopt the Company's net nuclear fuel property of \$201,880,000. (Appendix B, Line 11, Col. e.)

**4. Staff recommends capital lease obligations of \$13,486,000.**

The fourth component of rate base is capital lease obligations. Staff recommends the ALJ and Commission adopt the Company's projection of \$13,486,000. (Appendix B, Line 13, Col. e.)

**5. Staff recommends a total working capital of \$1,249,285,000.**

The fifth component of rate base is working capital. The Company forecasted that its total working capital requirement for the projected test year will be \$1,259,780,000 (Exhibit A-12 Schedule B1; Appendix B; Appendix E.) Staff's working capital of \$1,249,285,000 is \$10,496,000 less than the company's because Staff adjusted: a) other accounts receivable; b) move balances to 13-month averages; c) regulatory asset—charging forward; and d) regulatory asset—delivered fuel electrification pilot (DFEP). (Exhibit S-2; Appendix E, Line 93-96.)

**a. Staff recommends a \$7,257,549 reduction to working capital—other accounts receivable.**

Staff recommends a \$7,257,549 reduction to other accounts receivable. (Appendix E, Line 93.)

Staff witness Hecht recommends a \$7,257,549 reduction to other accounts receivable. (7 TR 4448.) The Company in response to Staff confirmed that the account Other Accounts Receivable has an embedded balance that is considered non-recoverable and non-utility related. (Exhibit S-7.0.) Based on the record evidence in this case, and the Company's non-objection in rebuttal, Staff recommends the ALJ and the Commission reduce the projected test year working capital by \$7,257,549.

**b. Staff recommends a \$1,680,000 reduction to working capital—move balances to 13-month averages.**

Staff recommends a \$1,680,000 reduction to move balances to 13-month averages. (Appendix E, Line 94.)

Staff witness Hecht recommends a \$1,680,000 reduction to move balances to 13-month averages. (7 TR 4448.) The Company's response to Staff confirmed and agreed to using an adjusted 13-month average historical year balance as a proxy for the test year for accounts that aren't volatile or known to have measurable changes. (Exhibit S-7.1.) Based on the record evidence in this case, and the Company's agreement in rebuttal (5 TR 1575), Staff recommends the ALJ and the Commission reduce the projected test year working capital by \$1,680,000.

**c. Staff recommends a \$900,000 reduction to working capital—regulatory asset—charging forward.**

Staff recommends a \$900,000 reduction to regulatory asset—charging forward. (Appendix E, Line 95).

Staff does not support DTE's Emerging Technology Fund becoming permanent. (7 TR 4429.) The fund costs include implemental costs shown in lines 22 (regulatory asset) and 12 (O&M) of Company Exhibit A-12, Schedule B5.9, page 4, in columns (e) and (f). (7 TR 4429.) The estimated costs are \$.9 million for the bridge period. Staff finds the fund too speculative. The group has only met a few times and it is too early to judge its effectiveness and overall value. (7 TR 4429). Consequently, it is too soon to a determine to make it a permanent program. Staff still supports the concept, but until the program matures, is uncomfortable with it becoming permanent or receiving additional funding. (7 TR 4429.)

Staff witness Freeman recommends disallowing the full requested amount for the Emerging Technology Fund (7 TR 4429), which also results in a \$900,000 reduction to the Company's regulatory asset—charging forward projection. (7 TR 4448.) Based on the record evidence in this case, and the Company's non-objection in rebuttal, Staff recommends the ALJ and the Commission reduce the projected test year working capital by \$900,000.

**d. Staff recommends a \$658,000 reduction to working capital—regulatory asset—delivered fuel electrification pilot.**

Staff recommends a \$658,000 reduction to regulatory asset—delivered fuel electrification pilot. (Appendix E, Line 96.)

Staff witness Revere recommends the Company's proposed DFEP be rejected in its current form (7 TR 4614-4616), which also results in a \$658,000 reduction to the Company's regulatory asset—delivered fuel electrification pilot projection. (7

TR 4448.) Based on the record evidence in this case, and the Company's non-objection in rebuttal, Staff recommends the ALJ and the Commission reduce the projected test year working capital by \$658,000.

The Company proposed a pilot, the DFEP, which would be "a five-year pilot to electrify space and water heating in homes currently heating with a delivered fuel." (4 TR 761.) Staff recommends the DFEP be rejected due to several flaws.

First, the Company's cost-benefit analysis was flawed. One flaw was the reliance on the PSCR base as the cost of power. (Revere, 7 TR 4614-4646; Peterson, 4 TR 806.) While Company witness Peterson claims this is appropriate as the PSCR base appears in the tariff and the revenue assumptions in the CBA rely on rates in the tariff, the witness is incorrect. No customer's rates actually include the PSCR base, as the rates in the tariff are based on the allocation of PSCR-related costs to the classes on various allocators; this results in different PSCR-related costs per-kWh in each class' rates. (Revere, 7 TR 4614-4615.) Therefore, use of the PSCR base as the cost of power results in an inaccurate CBA that cannot be relied on.

In addition, the Company failed to forecast potential increases in other costs, both distribution and generation, associated with the installation of heat pumps. As stated by Staff witness Revere, "[t]his is of particular concern as increasing electrification of transportation and heating will be increasing load in the current off-peak hours just as generation is trending more and more towards solar, which does not produce much, if at all, during these times." (7 TR 4615.) Energy market prices will also be impacted by expansion of heat pumps and generation changes

here and in other jurisdictions, which the Company also failed to account for. *Id.* Company witness Peterson claims that, as the DFEP is small, such impacts would be negligible. (4 TR 807.) While that may be the case, a pilot should also be geared toward examining what a program would look like “at-scale”. As such, ignoring these potentially substantial impacts is a fatal flaw.

The Company also failed to show why the exclusion of all other heating customers besides those served with a deliverable fuel is appropriate. (Revere, 7 TR 4615.) Company witness Peterson claims that customers converting from electric heating can already receive an energy efficiency rebate for a heat pump, and this is sufficient and appropriate. (4 TR 808.) The referenced rebate, however, is substantially lower than that proposed under the DFEP, and therefore should not be considered as if it were the same or somehow more appropriate.

The Company also failed to consider potential competitive concerns, such as ratepayers subsidizing the conversion of customers from a service provided in a competitive market to one provided by a regulated monopoly. (Revere, 7 TR 4615.) As stated by Staff witness Revere, “generally, when utilities are converting other customers from non-utility service to utility service, ratepayers are not expected to pick up the tab (for example, natural gas Customer Attachment Programs require the customers to whom service is being provided through main extensions cover the cost of such extensions).” (*Id.*)

Company witness Peterson also claims that the Commission has “set precedent to allow delivered fuel electrification programs that exclude natural gas

and electric resistance customers” by approving the settlement agreement in U-21224, which required Consumers Energy Company to propose an electrification pilot for unregulated delivered fuels only. (4 TR 809.) As Staff is sure the Company is aware, approval of a settlement agreement that requires a proposal is far from equivalent to Commission approval of said proposal, does not constitute the signatories’ or the Commission’s agreement with whatever that proposal may end up being, and Commission decisions do not set genuine precedent. That proposal will have to go through a contested case process where parties will have the opportunity to take positions on the proposal, whether in favor of or against, and the Commission will decide if approval is appropriate based on the record so developed, as they must in the instant case. For these reasons, the argument should not be considered supportive of the DFEP, particularly in light of the identified deficiencies.

Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (collectively MNSC) witness Chris Neme proposes a number of changes to the Company’s DFEP proposal that exacerbate the issues discussed above. Specifically, MNSC witness Neme recommends increasing participation in the pilot from that proposed by the Company and increasing rebate amounts (with additional rebate increases for low-income customers). (6 TR 3514-3515.) As shown above, the benefits claimed for the Company’s initial proposal are insufficiently supported, and the costs are not appropriately identified; MNSC witness Neme’s proposed changes would exacerbate

these issues and should therefore be rejected. (Revere, 7 TR 4629.) MNSC witness Neme further claims that better understanding how to grow the market for heat pumps should be the goal of the pilot, citing decarbonization and heating savings to participants. (6 TR 3492-3496.) These benefits do not justify ratepayers funding the program, however; the concentration should be on benefits to ratepayers as ratepayers for a ratepayer-funded program as further discussed elsewhere in this brief in the context of electric vehicle programs. (7 TR 4630). For these reasons, MNSC witness Neme's proposed changes should be rejected.

For all of the reasons above, the Company's DFEP proposal should not be approved in the instant case, with or without proposed changes. Instead, the Company should be required to meet with Staff and intervenors to develop a reasonable proposal to address the identified deficiencies, if possible.

**B. Staff recommends several reductions to the Company's capital expenditures, along with some approvals.**

As discussed above, Staff's total utility plant is \$148.347 million lower than the Company's because Staff adjusted the Company's: 1) production; 2) nuclear; 3) distribution; 4) demand side management; 5) information technology; 6) corporate staff; 7) charging forward; and 8) contingency capital expenditures. (Appendix E.) The adjustments are explained below.

**1. The Commission should exclude \$178,970,203 from DTE's projected production capital expenditures.**

Staff recommends the removal of \$178,970,203 in production capital expenditures, which reduces rate base by \$70,124,362. Appendix E, Line 32, Col. b and f.) The specific exclusions are discussed in the following.

**a. Staff recommends the capital spending associated with Steam Generation: Non-Routine Additions – Monroe Bottom Ash Conversion should be reduced by \$39,859,725. (Appendix E, Line 2.)**

Staff recommends adjustments to steam generation capital expenditures for the early retirement of Monroe Units 3 and 4. In the Company's integrated resource plan (IRP) in Case No. U-21193, DTE Electric proposed an accelerated retirement of 2028 for Monroe Units 3 and 4. Staff was supportive of the accelerated retirement of 2028 for Monroe Units 3 and 4 in the Company's IRP case. (7 TR 4510). Furthermore, the Commission has now approved DTE Electric's IRP with the accelerated retirement of Monroe Units 3 and 4 by December 31, 2028. MPSC Case No. U-21193, 7/26/2023 Order, p 3.

In conjunction with the early retirement in the IRP, Staff witness Lisa M. Kindschy explained that the Environmental Protection Agency (EPA) recently revised its 2020 Effluent Limitation Guideline (ELG) rules which now allow DTE Electric to opt-in to a 2028 retirement for Monroe Units 3 and 4, and thereby avoid certain capital expenditures that were previously required. (7 TR 4510-11.) Staff learned that DTE Electric has submitted its notice of planned participation to the

Department of Environment, Great Lakes, and Energy with a 2028 cessation of coal combustion at Monroe Units 3 and 4. (7 TR 4511.)

Staff witness Kindschy explained that the Company was previously required to complete a Bottom Ash Conversion project at its Monroe plant to eliminate the use of water for transporting bottom ash. Since the Company is now able to opt-in to a 2028 retirement for Monroe Units 3 and 4, witness Kindschy testifies that the Bottom Ash Conversion project is no longer required. (7 TR 4511.) Staff witness Kindschy determined the adjustment for the Bottom Ash Conversion project by removing the capital expenditures for Monroe Units 3 and 4 beginning in January 2023 through the end of the test period. In addition, witness Kindschy recommends that half of the common capital expenditures be removed as an approximation until actual amount are known. (7 TR 4511-4512; Exhibit S-21.1, p 2.) Staff notes that actual capital expenditures incurred in 2023 prior to the ruling in the IRP and the ability to opt-in to a 2028 retirement date can be included for review in the Company's next rate case. (7 TR 4512.) In total, Staff recommends that \$39,859,725 in capital expenditures related to the Monroe Units 3 and 4 Bottom Ash Conversion project be removed from this case.

- b. Staff recommends capital spending associated with Steam Generation: Routine – Monroe Units 3 and 4 should be reduced by \$48,717,728. (Appendix E, Line 22.)**

Staff recommends additional capital expenditure reductions based on the retirement of Monroe Units 3 and 4 in 2028. In direct testimony, Company witness

Justin L. Morren identified the avoidable and unavoidable amounts for reliability-based capital projects over \$1 million at Monroe Units 3 and 4 assuming a 2028 retirement. (5 TR 2343.) Staff witness Kindschy recommends all of these amounts be removed from this case to be consistent with the Company's IRP. (7 TR 4512.) In addition to the capital expenditures for projects over \$1 million identified by the Company, witness Kindschy recommends that \$6,608,451 for avoidable capital projects under \$1 million also be removed from the case. (7 TR 4514-4515; Exhibit S-21.3.) The Company did not dispute the removal of either of these capital expenditures in its rebuttal testimony. (5 TR 2417-2423.) Therefore, Staff recommends the removal of the avoidable capital expenditures for Monroe 3 and 4 identified by the Company in direct testimony for projects over \$1 million and the amount identified by Staff through discovery for projects under \$1 million. (7 TR 4512-4515; Exhibit S-21.4.)

As previously discussed, Staff recommends that capital expenditures for the Bottom Ash Conversion project at Monroe Units 3 and 4 be removed. (Section III.B.1.a.) Staff witness Kindschy explains that the DCS & Control Room project was being updated to support the new bottom ash handling system. (7 TR 4513; Exhibit S-21.2.) Since the Bottom Ash Conversion project is no longer necessary at Monroe Units 3 and 4, witness Kindschy recommends the removal of all capital expenditures for the DCS & Control Room project for Monroe Units 3 and 4 that was being installed to support the bottom ash conversion project. She recommends the removal of \$1,176,098 for the 11 months ending November 30, 2023, and

\$3,858,314 for the 12 months ending November 30, 2024, for the DCS & Control Room project. (7 TR 4513.) Staff notes that the Company can request recovery of future amounts related to this project for review and recovery in its next rate case to the extent those expenditures are necessary to support Monroe plant operations.

Staff made a final adjustment to the Company's generation capital expenditures related to the Monroe Unit 3 Waterwall Tubes project. Staff witness Kindschy recommends that the amount for the Monroe Unit 3 Waterwall Tubes project be reduced to half of the total costs for 2024. (7 TR 4513.) The Company determined it could scale back this project if Monroe Unit 3 retired in 2028, reducing the project from its original scope of 4000 feet to only replacing 2000 feet of waterwall tubes in the boiler. (7 TR 4513-4514.) Staff witness Kindschy argued that it was not clear why the avoidable costs for this project were not closer to half since the scope of the project was being cut in half. Therefore, Staff removed an additional amount so the capital expenditures for this project are half of the projected costs for the Monroe Unit 3 Waterwall Tubes project in 2024. (7 TR 4514.) Similar to the capital expenditures related to the Bottom Ash Conversion project and DCS & Control Room project, the Company can request recovery of future capital expenditures for this project for review and recovery in its next rate case to the extent that the project is necessary to support Monroe plants operations.

**c. Capital spending associated with Other—Non-Routine should be reduced by \$90,392,750. (Appendix E, Line 30.)**

Staff recommends four adjustments to other – non-routine, i) Blue Water energy center; ii) Blackstart Project; iii) Slocum Battery Project; iv) 2025/2026 Battery.

**i. Capital spending associated with Blue Water Energy Center should be reduced by \$8,100,000. (Appendix E, Line 24.)**

Staff recommends the Commission adopt its proposed disallowance of \$8,100,000 in historical capital expenditures for the Blue Water Energy Center project. (Appendix E, p 1, line 24). Staff’s recommendation is aligned with the Commission’s disallowance of \$8.1 million in contingency expenses in the Company’s previous electric rate case, Case No. U-20836, due to a lack of support for these projections.<sup>2</sup> Similar to the previous case, while these capital expenditures were included in the Company’s requests for recovery, they were not supported. (7 TR 4361). When asked if these costs had been fully identified and reconciled in the final project cost review, the Company stated that it “expects to know final project costs after performance testing in the spring of 2023.” (Exhibit S-17.0). Although the Company claimed that it would know final costs in the spring of 2023, it made no effort to provide further evidence to support these costs in the record. In his testimony on behalf of the AG, Mr. Coppola recommended an

---

<sup>2</sup> MPSC Case No. U-20836, 11/18/22 Order, p 41.

equivalent \$8.1 million disallowance, but that these amounts be removed from the 2022 and 2023 projected expenses for this project. (6 TR 3641).

In rebuttal, the Company did not directly oppose Staff's recommended adjustment of \$8.1 million in 2021 capital expenditures. Instead, the Company claims that this adjustment and a separate adjustment Staff is recommending to 2023 projected expenditures are both accounting for the same capital expenditures, essentially double counting this amount. (5 TR 2425). However, the Company's claim is incorrect, as these are two separate adjustments. While in the previous case the \$8.1 million disallowance was for projected contingency, in this case these expenses are no longer projected. While these funds may have indeed been spent, the Company was unable to identify what these funds were spent on or even confirm if they were spent at all. Therefore, parties in the case and the Commission have no way to assess if they were spent in a way that is reasonable and prudent. While the Company claims that the two proposed disallowances were for identical capital funds, the Company was unable to account for the \$8.1 million in 2021 expenditures Staff recommended disallowance of and has only identified the \$6.8 million Staff recommended disallowance of as 2023 projected contingency. (Exhibit S-12.2, p 3). Therefore, both of Staff's recommended disallowances for the BWEC project are reasonable and should be adopted by the Commission.

**ii. Capital spending associated with Blackstart Project 1, 2, and 3 should be reduced by \$6,525,750. (Appendix E, Line 25-27.)**

Staff recommends the Commission adopt its proposed disallowances for the bridge period and test year projected capital expenditures for the three Blackstart projects included in the Company's recovery requests, totaling \$4,794,000 and \$1,731,750 in the bridge period and test year, respectively. (Appendix E, p 1, lines 25-27.) In the previous electric rate case, the three projects, Blackstart Project #1, Blackstart Project #2, and Blackstart Project #3, were all included under a single line item, Blackstart Infrastructure, Site Security, & NERC Compliance. The Commission disallowed all projected capital expenditure requests for these projects due to evidence presented by parties casting doubt on the reliability of these estimates.<sup>3</sup> Staff's partial disallowance would align approved capital for these projects with the Company's projected or actual monthly capital expenditure projections for the bridge period. (7 TR 4366.) Additional disallowances in the test year for Blackstart Project #2 are aligned with the overestimations seen for this project when comparing actual costs with the Company's previous cost projections. (*Id.*)

The AG and ABATE both recommended a full disallowance of all projected and actual project costs for the Blackstart projects. (6 TR 3700; 4 TR 1127.) Mr. Coppola filed testimony on behalf of the AG, which pointed to multiple requests for additional information made through the discovery process; ultimately finding the

---

<sup>3</sup> MPSC Case No. U-20836, 11/18/22 Order, p 41.

Company's answers unsatisfactory to justify the need for these projects and the corresponding request for recovery. (6 TR 3699-3700.) Ms. York filed similar testimony on behalf of ABATE, recommending the Commission disallow all project costs due to the lack of detail surrounding the project work which would take place through the bridge period and test year. (4 TR 1127.)

In his rebuttal testimony on behalf of the Company, Mr. Morren argues against the disallowances recommended by the Staff, the AG, and ABATE. Regarding the arguments made on behalf of ABATE, Mr. Morren argued that, aside from referencing the project disallowances in the previous case and the supporting project documentation provided in this case for these projects, Ms. York provided no specific analysis nor reasoning for her recommended disallowances. (Morren 5 TR 2394 - 2396.) Regarding a similar disallowance recommended by the AG, Mr. Morren claimed that the Company was responsive to the AG's discovery questions to the extent possible given the sensitive nature of the projects and provided a summary of the Company's responses in his testimony. (5 TR 2267-2269). Finally, in opposition to Staff's recommended partial disallowances, the Company argued that the methodology used was inconsistently applied; as Staff is not proposing to add funding to projects which were under projected compared to actual spending. (5 TR 2266). While this argument appears to make some sense on its surface, it ignores the historical trends for these projects. Not only do Staff's proposed disallowances align the approved capital with updated actual and monthly projections for the bridge period, but there is also historical precedent to support

making such an adjustment without even considering this fact. No weight should be given to the Company's arguments that the methodology employed by Staff to support its disallowance is inconsistent, as the Blackstart projects have been historically overestimated in every instance the Company has provided projections, both in this case and the previous rate case. As Staff has identified, for the Blackstart projects the Company overestimated its projections in the previous rate case by 70% when compared to actual expenditures. (7 TR 4364; Exhibit S-17.2.) Therefore, the Commission should adopt Staff's recommended partial disallowance of projected expenditures for the Blackstart projects.

**iii. Capital spending associated with Slocum Battery Project should be reduced by \$3,540,000. (Appendix E, Line 28.)**

Staff recommends that the Commission adopt its proposed partial disallowance of bridge period capital expenditures for the Slocum battery pilot, totaling \$932,000 and \$975,000 in 2022 and 2023, respectively, and a partial disallowance of \$1,633,000 in test year project capital expenditures totaling \$3,540,000. (Appendix E, p. 1, line 28.) The recommended adjustments for the Slocum battery pilot align the requests in 2022 with actual amounts spent during that year and adjusts 2023 and 2024 expenditures to reflect this historical overestimation. (7 TR 4370). Adjusting 2023 and 2024 projected costs based on the historical 2022 overestimation is reasonable, as Staff has demonstrated that this project has consistently been overestimated on every occasion in which the Company has requested recovery of projected costs. (TR 4370-4371; Exhibit S-17.2.)

The AG recommended a full disallowance of all expenditures for Slocum. Mr. Coppola filed testimony on behalf of the AG, and identified several perceived flaws with the Slocum pilot that supported this recommendation. The main issue Mr. Coppola appears to take with this pilot is the lack of evidence that Slocum will result an economic resource for the ratepayers. (6 TR 3703). Mr. Coppola stated that the analysis the Company presented which showed \$2 million in annual PSCR savings was not a proper cost benefit analysis but rather a presentation of unconnected and unexplained values that did to present a clear analysis of the pilot's economics. (6 TR 3705-3706). Finally, Mr. Coppola argued that the experience gained by the Company through the development and operation of the Slocum pilot is only valuable if battery storage ends up as an economically viable technology. (6 TR 3704-3705).

In his rebuttal testimony on behalf of the Company, Mr. Morren opposed the disallowances supported by Staff and the AG. Regarding the AG's proposed disallowance, Mr. Morren pointed out that the issues raised in Mr. Coppola's testimony are generally the same arguments which were addressed when this pilot was proposed and approved in the Company's last rate case, Case No. U-20836. (5 TR 2400). Mr. Morren noted that in Case No. U-20836, the Commission found Staff's confidence in the reasonableness of this pilot persuasive, and ultimately approved partial funding. (*Id.*) Regarding Staff's proposed partial disallowance, Mr. Morren's argument echoed that of other partial disallowances recommended by Staff; these adjustments were inconsistently applied only when a project has been

overestimated and not in the opposite scenario. (5 TR 2401). This argument ignores the historical precedent that has been set for this project. Specifically, Staff's proposed adjustment would align amounts approved for 2022 with the actual costs, as the Company's requests were overestimated by 12%. (7 TR 4369). This amount of overestimation was then applied to 2023 and 2024 amounts to determine the adjustments to these requests (7 TR 4370). Considering that project costs have been consistently overstated, including projected costs in the previous case being overestimated by 86% of actual costs over the same period, there is significant evidence to suggest that future projected costs may be overstated as well. (*Id.*) Absent any evidence to the contrary provided by the Company, it is reasonable to expect that projected capital expenditures for this project will continue to be overestimated in the test year, which warrants Staff's disallowance. Therefore, the Commission should adopt Staff's partial disallowance of bridge period capital expenditures for the Slocum battery pilot, totaling \$932,000 and \$975,000 in 2022 and 2023, respectively, and a partial disallowance of \$1,633,000 in test year project capital expenditures totaling \$3,540,000.

**iv. Capital spending associated with 2025/2026 Battery should be reduced by \$72,227,000. (Appendix E, Line 29.)**

Staff recommends the Commission adopt its proposed partial disallowance of \$15,098,000 and a full disallowance of \$57,129,000 in projected bridge period and test year capital expenditures, respectively, for the 2025/2026 Battery project totaling \$72,227,000. (Appendix E, p 1, line 29). This adjustment aligns the

approved capital expenditures for this project with the \$9 million in funding the Company has received internal budgetary approval for. (7 TR 4375). This project still is in the early phases of development, with contracts for project development and for engineering, procurement, and construction having not yet been finalized as of the close of the record in this case. (7 TR 4373). Additionally, the scope of this project has changed since the requests for recovery were made in the initial filing; the Company consolidated the first 4 years of its battery development (220 MW) into this single project. (*Id.*) Not only are the projected costs no longer reflective of the total project development but were also based on 2022 national estimates from the National Renewable Energy Laboratory, instead of project specific costs developed through an executed contract. (7 TR 4374). This national estimate does not provide the level of detail necessary to determine reasonable and prudent costs to approve for this project.

The AG and ABATE both recommended a full disallowance of all projected costs for the 2025/2026 Slocum Battery project. (6 TR 3708; 4 TR 1132). Mr. Coppola filed testimony of behalf of the AG, and argued that the proposed battery was premature, as with the Slocum battery pilot not fully installed and costs not known, the Company has not shown that scaling up to a larger commercial battery would be economic. (6 TR 3708). Mr. Coppola also points out that this battery project is part of a battery deployment plan that was proposed in the Company's IRP, which was not approved as of the date of the initial filing of this case. (*Id.*) Ms. York filed testimony on behalf of ABATE, which identified several reasons for

her recommended full disallowance. Ms. York points out that it is not clear whether the Company has received full internal budgetary approval for this project, that a clear timeline of project work was not provided, and that the project scoping document identifies only a fraction of the project capital as being spent in 2023 with no further project spend identified in 2024-2026. (4 TR 1132). Ultimately, Ms. York concludes that there was effectively no support provided for this project in the filing and recommended a full disallowance. (*Id.*)

In rebuttal testimony filed on behalf of the Company, Mr. Morren argued against the disallowances proposed by Staff, the AG, and ABATE. In response to the full disallowance proposed by the AG, Mr. Morren argued that the IRP was comprehensive and ultimately resulted in the development of a PCA which includes the current project as part of the Company's battery deployment plan. (5 TR 2403). Mr. Morren also disputed that the concerns raised by Ms. York warrant her recommended full disallowance and pointed to the \$9 million in approved project capital for engineering and the fact that full budgetary approval is expected later this year. (*Id.*) Attempting to justify its requests for cost recovery in this case, Mr. Morren emphasized that the Company has a limited time window to execute this project while qualifying for specific benefits, such as using the existing interconnection rights for the retired Trenton Channel unit 9. (5 TR 2404). Mr. Morren's testimony also pointed to the economies of scale this project achieves by consolidating three years of planned battery build into a single project. (*Id.*)

While Staff understands the Company's desire to execute this project in a timely manner that allows for the capture of all the benefits identified, disregarding Staff's proposed adjustment is not the best way to accomplish this. Staff's disallowances would still provide the Company with the necessary funding to continue the development of this project, while allowing for costs to be refined through the execution of contracts for development and construction of the battery system. Staff's recommended adjustment strikes the right balance between allowing for funds necessary to ensure this project can be executed in a way that captures time sensitive values, while also ensuring rate payers are not paying for costs which have not been properly defined and are only based on rough national estimates. Therefore, the Commission should adopt Staff's partial disallowance of \$15,098,000 and a full disallowance of \$57,129,000 in projected bridge period and test year capital expenditures, respectively, for the 2025/2026 Battery project for a total disallowance of \$72,227,000.

This project had been included by DTE in its projected construction work in progress (CWIP) and therefore not subject to depreciation expense. (5 TR 1571.) No reduction in depreciation expense was made for this item. Additionally, it is unnecessary to make any corresponding reductions to CWIP and allowance for funds used during construction (AFUDC) because those changes are onerous and would have zero impact on the revenue deficiency. DTE agreed in discovery response STDE-20.1a and 20.1b. (Exhibit S-24.)

**2. The Commission should make adjustments due to the timing of the Fermi Generator Project.**

Staff recommends the following adjustments because the timing of the Fermi Generator Project has changed: Reduce plant in service by \$257,627,500, increase construction work in progress by \$257,627,500, reduce accumulated depreciation by \$3,054,500, reduce depreciation expense by \$6,109,000, increase allowance for funds used during construction by \$11,079,000. This results in rate base increasing by \$3,054,500, and the revenue deficiency decreasing by approximately \$20.8 million overall. In discovery response STDE-21.1 (Exhibit S-25), DTE stated that “DTE Electric has changed the projected installation date of the Main Unit Generator project (depicted on page 4, line 2 of Exhibit A-12, Schedule B5.3) to the next refueling outage (RF23), which is beyond the projected test year in the instant case. The impact of this change results in a reduction to DTE Electric’s proposed revenue deficiency of \$20.852 million.” (Exhibit S-25; Appendix E, Line 34.)

**3. The Commission should exclude \$245,732,000 from DTE’s projected distribution capital expenditures.**

Staff recommends disallowance of \$245,732,000 of the company’s distribution capital expenditures, which reduces rate base by \$16,227,621. (Appendix E, Line 41, column b and f.) The specific exclusions are discussed in the following.

- a. **Capital spending associated with strategic capital program— City of Detroit Infrastructure Upgrades of \$172,298,000 should be disallowed. (Appendix E, Line 38.)**

Staff recommends that Capital spending associated with strategic capital program—City of Detroit Infrastructure Upgrades of \$172,298,000 should be disallowed.

Staff recommended disallowance regarding the Company's City of Detroit Infrastructure (CODI) program can be summarized as:

1. \$56.4 million for the Bridge Period (11 months ending 11/30/2023), and
2. \$115.9 million (\$172.5 million – \$56.7 million) for the test year ending 11/30/2024.

DTE Electric's CODI is a program to address aging infrastructure and to better serve customers with safe and reliable power in a core area around downtown Detroit. According to page 23 of Company witness Deol's testimony:

There are 31,800 customers served in this area including 27,486 residential, 4,299 commercial, and 15 industrial customers. In addition to residential, commercial, and industrial customers including healthcare facilities and universities, this area of Detroit is also vital to tourism and recreation in the region, with an abundance of shopping, sports venues, and parks. [2 TR 208.]

The reasons the CODI program is needed is explained by witness Deol in his testimony:

Significant portions of the electrical infrastructure in Detroit were placed in service in the early part of the 20th century, and much of that earlier infrastructure remains. Additionally, certain sections of Detroit have seen significant economic growth. Redevelopment in the City of Detroit is stressing this aging infrastructure, and new customer load cannot be served with existing capacity. The downtown CODI

area has been experiencing load growth since 2012, with potential for up to 20% of additional load growth by the end of 2023. [2 TR 209.]

The following table outlines the Company’s request for its CODI program in the current rate case, and the information was obtained from the company Exhibit A-12 B5-4; however, Staff added the amounts to produce the sum at the bottom, shown in bold.

Michigan Public Service Commission					Case No.:	U-21297		
DTE Electric Company					Exhibit:	A-12		
Projected Capital Expenditures					Schedule:	B5.4		
Distribution Plant - Infrastructure Redesign and Modernization					Witness:	S. S. Deol		
(\$500)					Page:	9 of 21		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
Capital Expenditures								
		Historical	Projected Calendar Year			Bridge Peri	Test Year	
Line		12 mos. ended	12 mos. ending	12 mos. ending	12 mos. ending	23 mos. en	12 mos. endir	In Service
No.	Description	12/31/2021	12/31/2022	12/31/2023	12/31/2024	11/30/2023	11/30/2024	Date
42	CODI: Charlotte Network Upgrade	8,100	8,286	6,658	11,673	14,389	11,255	12/31/2025
43	CODI: Targeted Network Secondary Cable Replacement	869	1,789	3,800	3,800	5,272	3,800	12/31/2025
44	CODI: Corktown Substation	13,301	1,360	-	-	1,360	-	12/31/2022
45	CODI: Islandview Substation	3,264	12,912	35,745	46,424	45,679	45,534	12/31/2028
46	CODI: CATO Substation Expansion	-	319	10,795	13,300	10,214	13,091	12/31/2027
47	CODI: Howard Conversion	-	2	700	15,000	644	13,808	12/31/2030
48	CODI: Midtown Substation Expansion	6,510	2,234	1,803	-	3,887	150	12/31/2023
49	CODI: Alfred Substation Expansion	417	53	4,137	11,782	3,846	11,145	12/31/2024
50	CODI: Garfield Network Upgrade	11,177	18,193	30,000	36,220	45,693	35,701	12/31/2028
51	CODI: Kent/Gibson Conversion	211	2,051	19,810	39,751	20,209	38,089	12/31/2027
	<b>Total amount</b>	<b>43,849</b>	<b>47,199</b>	<b>113,448</b>	<b>177,951</b>	<b>151,193</b>	<b>172,572</b>	

Staff reviewed and analyzed the capital projects and scope of work that DTE presented in its testimony and discovery responses, recognizing that the CODI program is indeed necessary to address the downtown Detroit aging distribution system and to provide safe and reliable energy to local customers. Staff supports the Company’s execution of the CODI program; however, Staff has different projected amounts for the bridge and test years compared to DTE’s projection.

DTE Electric spent \$43.8 million during 2021 and \$47.2 million during 2022, which is an approximate 8 %  $(47.2 - 43.8) / 43.8$  increase. Staff found no evidence through Company witness Doel’s testimony, nor from the discovery response, that

DTE will substantially increase its manpower or accelerate the CODI program spending from 2022 to 2023 and further into 2024 to reach \$172.6 million. The additional information in Company Exhibit A-23, Schedule M-7, pp 339-340, Exhibit 11.4.4—Projected Costs and Timeline, does not clearly support the substantially escalated spending for the test year period either.

The Company's witness Mr. Deol stated in his rebuttal testimony that the "more detailed scope of work is provided in Exhibit A-23, Schedule M5 for each project" (2 TR 273); however, that is just a projective scope and schedules. Mr. Deol also mentioned in his rebuttal testimony that the number of the Company's Monthly Average Overhead (OH) Contractors increased from 293 to 659 as shown in Table 3 of his rebuttal (2 TR 274) to support his theories that DTE will have the resources and organization to manage this level of work; however, in the same Table 3, the number of the Monthly Average OH contractors was 401 in January of 2022 and 582 in January of 2023, respectively. With the 582 of the Monthly Average Overhead Contractors in the first month of 2023, the actual spending for the CODI program is only \$14.6 million (provided by DTE, shown in Exhibit S-20.2) for the first quarter of 2023. Obviously, the Monthly Average Overhead Contractor number cannot be used as an indicator. Therefore, Staff asserts that the higher number of Monthly Average OH contractors does not necessary imply more expensive the CODI program expenditure would be.

As stated above, Staff had a hard time justifying the cost of \$172.6 million for the test year ending 11/30/2024. The projected amount of \$172.6 million is nearly a

four-fold increase to the \$43.9 million which was actual spent during 2021. Ultimately Staff found that there was no significant reason given in DTE Electric's direct and rebuttal testimonies for why the CODI program's capital cost suddenly jumped to \$172.6 million, for the test year ending in 11/30/2024, especially given that the actual CODI program capital expenditures were \$43.8 million, \$47.2 million, and \$14.6 million for 2021, 2022 and the first quarter of 2023, respectively. Staff notes that the actual CODI program spending from 2021 to 2022 increased approximately 8%, so Staff used a rounded up-escalation rate of 10% and applied that to the actual cost of \$47.2 million in 2022 to get \$51.9 million ( $\$47.2 * 1.1$ ) as the projected capital cost for 2023. Staff added another 10% to get \$57.1 million ( $\$51.9 * 1.1$ ) as the projected expenditure amount for 2024. The test year projected cost of the CODI program will be \$56.7 million. ( $\$51.9 \text{ million} * 1/12 + \$57.1 \text{ million} * 11/12$ ). The disallowed amount for the test year was calculated to be \$115.872 million. ( $\$172.572 \text{ million} - \$56.7 \text{ million}$ ), with the same approach. Additionally, Staff also calculated the disallowed amount for the bridge period (11 months ending 11/30/2023) as \$56.4 million. ( $(\$113.4 - \$51.9 \text{ million}) * 11/12$ , with the \$113.4 million being the Company's 2023 projection).

This program had been included by DTE in its projected construction work in progress (CWIP) and therefore not subject to depreciation expense. (5TR 1571). No reduction in depreciation expense was made for this program. Additionally, it is unnecessary to make any corresponding reductions to CWIP and allowance for funds used during construction (AFUDC) because those changes are onerous would

have zero impact on the revenue deficiency. DTE agreed in discovery response STDE-20.1a and 20.1b. (Exhibit S-24).

**b. Capital spending associated with strategic capital programs should be reduced by \$69,592,000. (Appendix E, Line 39.)**

Staff, through its witness Nicholas Evans, recommends a 10% downward adjustment to all Strategic Capital programs except for the strategic and service undergrounding pilot and the CODI projects. (7 TR 4412.) Strategic Capital programs are described by Company witness Bryant F. Miller:

Strategic capital projects and programs include work the Company performs to improve safety, reliability and operability, and grid modernization. These investments are subcategorized into three areas or investment pillars: Infrastructure Resilience and Hardening, Infrastructure Redesign and Modernization, and Technology and Automation. [5 TR 2841.]

Mr. Evans recommended a 10% downward adjustment to all but two Strategic Capital programs because the Company has yet to demonstrate that it can project a certain amount of capital expenditures for the test year for Strategic Capital programs and subsequently spend that amount. (7 TR 4415.)

In Case No. U-20162, the Company projected \$432,939,000 for Strategic Capital programs for that case's test year, which ran from May 1, 2019, to April 30, 2020. Staff calculates the Company only spent \$311,389,000, or 71.9%, based on actual spending in 2019 and 2020.

In Case No. U-20561, the Company projected \$393,633,000 for Strategic Capital programs for that case's test year, which ran from May 1, 2020, to April 30,

2021. Staff calculates the Company only spent \$324,797,000, or 82.5%, based on actual spending in 2020 and 2021.

In Case No. U-20836, DTE Electric's last electric rate case, the Company projected \$797,767,000 the projected test year, which runs from November 1, 2022, to October 31, 2023. Therefore, actual spending for this time period is not available yet. (7 TR 4415-4416.)

The Staff recommends a 10% reduction be applied to all Strategic Capital programs, excluding the strategic and service undergrounding pilot and the CODI projects, in order to protect ratepayers from potential underspending in the projected test year. By investment pillar, this overall adjustment breaks down as follows:

Infrastructure Resilience and Hardening:--\$24,447,000

Infrastructure Redesign and Modernization:--\$35,190,800

Technology and Automation:--\$9,954,000

This adjustment to projected Strategic Capital expenditures does not include expenditures requested for inclusion in the investment recovery mechanism. (7 TR 4416.) Additionally, if the Company ends up spending its projected test year forecast from Case No. U-20836, Staff will recommend recovery of the incurred expenditures if they are found to be reasonable and prudent. If this happens, this will convince Staff that the Company can forecast and then spend prudently its projected test year capital expenditures. (7 TR 4416-4417.)

DTE witness Miller states that the Company is confident it will be able to deliver on the higher levels of projected investment due to the steps the Company has taken to ensure that the strategic capital requested is invested in strategic projects and programs. These steps include increasing the labor force, leveraging partnerships, strengthening project management oversight, and strengthening supply chain oversight. The Company states that these steps have been successful at reaching its forecasted strategic capital requests shown by the forecasted \$696 million vs an invested \$712 million for calendar year 2022 in Case No. U-20836. (5 TR 2882-2883.)

Staff still recommends a 10% reduction to all Strategic Capital programs excluding the strategic and service undergrounding pilots and the CODI projects. DTE Electric has shown it can forecast capital expenditures for Strategic Capital for a bridge period and then spend it, but the Company has yet to prove it can forecast Strategic Capital expenditures for a test year and then subsequently spend that amount.

Consistent with some earlier Staff brief sections, DTE included some of these programs in its projected construction work in progress (CWIP) and therefore not subject to depreciation expense. (5 TR 1571 – 1572.) Again, it is unnecessary to make any corresponding reductions to CWIP and allowance for funds used during construction (AFUDC) because those changes are onerous would have zero impact on the revenue deficiency. DTE has agreed with this handling in discovery response STDE-20.1a and 20.1b. (Exhibit S-24.)

**c. Capital spending associated with Infrastructure Redesign and Modernization Pilot—Strategic and Service Undergrounding should be reduced by \$3,842,000. (Appendix E, Line 40.)**

The Company piloted moving rear-lot overhead assets to rear-lot underground infrastructure on the Appoline DC 1346 circuit in Detroit. Engineering for the pilot began in 2018 and construction started in 2019. The goals of the pilot were to determine actual installation costs, understand customer acceptance, and determine opportunities to improve cost and construction efficiency. (7 TR 4412.)

The Company is proposing an additional undergrounding pilot on the Fairmount DC 1593 circuit in Detroit. This project will relocate overhead rear-lot assets to front-lot underground residential distribution cable in a two-block area. Engineering is being completed and design is expected to start late in the first quarter or early in the second quarter with the intent of starting construction in late fall 2023. Construction is scheduled to be complete by the end of 2024. (7 TR 4412-4413.)

On pages 110–112 of the November 18, 2022, Order in U-20836, the Commission stated:

In the August 25, 2021 order in Case Nos. U-21122 *et al.* and the September 8 order, the Commission directed investor-owned utilities to provide strategic undergrounding proposals so that the Commission may gain a better understanding of the costs and benefits of undergrounding. On page 74 of the September 8 order, the Commission noted that “this topic of undergrounding is also raised in Case No. U-20836, DTE Electric’s pending general rate case . . .” Although DTE Electric claims that the Appoline pilot is complete and all necessary learnings have been provided, the Commission disagrees. The Commission’s directive for strategic undergrounding proposals was founded in the fact that the Commission may gain a better understanding of costs and

benefits, and this information has not yet been communicated to the Commission. As noted by the ALJ, the Commission and interested stakeholders would benefit from a full report on the Appoline pilot including, but not limited to, a benefit/cost analysis (BCA) that considers other less costly alternatives such as tree trimming, an analysis of the interaction between undergrounding and grid hardening or 13.2kV conversion, a description of how undergrounding may be included in a distribution plan, and a discussion of health, safety, reliability, and vulnerability. Therefore, the Commission directs the company to submit a full report, including a BCA and the other information noted above, in its next rate case.

Furthermore, the Commission does not intend to forestall the continued learnings that could be derived from subsequent strategic undergrounding pilots as it awaits the submission of a full report on the Appoline pilot. For future proposed strategic undergrounding pilots, however, the Commission expects DTE Electric to provide how the benefit/cost of the proposed undergrounding pilot compares to that of other solutions the company is currently employing to enhance the reliability of the distribution system. This includes, but is not limited to, benefit/cost comparisons of strategic undergrounding alongside the benefit/cost of employing grid hardening, grid conversion, tree trimming, or other solutions. Therefore, until the Appoline pilot is complete and a full report is available, and until a more robust analysis of the benefit/cost of strategic undergrounding is available, the Commission finds it reasonable and prudent to approve a \$15.1 million disallowance for the 10 months ending October 2022 and a \$36.8 million disallowance for the projected test year. [*In re DTE Electric's 2022 Rate Case*, MPSC Case No. U-20836, 11/18/2022 Order, pp 110-112.]

The Company did not provide a full report on the Appoline pilot in this rate case. The report the Company did provide, titled "Appoline Report", provides a background on the pilot, the baseline costs of the pilot, the forecasted costs of future work, the status of Appoline pilot, a summary of lessons learned, and conclusions. While there is also a section in the report titled "Strategic Undergrounding Benefit Cost Analysis and Alternatives", a complete benefit cost analysis was not provided, there was no description of how undergrounding may be included in a distribution

plan, and there was no discussion on health, safety, reliability, and vulnerability. (7 TR 4414.) In fact, the report states on page 6:

For the Company to complete the benefit cost analysis, it needs a full year of 2022 data. At the time of this filing, the 2022 reliability data and wire down data is still being compiled and audited. Data will be available in the first quarter of 2023, and the benefit cost analysis will take place at that time. [Company Exhibit A-23, Schedule M10, p 6.]

The Company also did not provide a benefit/cost analysis of the proposed undergrounding pilot on the Fairmount DC 1593 circuit in Detroit. Company witness Satvir Deol provides two pages of testimony on the proposed pilot, in which he describes the pilot, explains why the Fairmount DC 1593 circuit was selected, the timing of the pilot, and what the Company expects to accomplish with it. However, neither Mr. Deol's testimony nor any exhibits provide a benefit/cost analysis of the proposed Fairmount pilot, so the Company cannot and does not compare it to the benefit/cost analysis of other solutions, such as grid hardening, grid conversion, or tree trimming. In short, the Company did not follow the Commission's order that concluded the last rate case. For that reason, Staff, through its witness, Nicholas Evans, recommends a full disallowance of the \$1,925,000 projected for the 11 months ending 11/30/2023 and \$1,917,000 projected for the test year. (7 TR 4414-4415.)

DTE witness Mr. Deol rebutted Mr. Evans's position, stating that the full year of reliability data from 2022 required to conduct the analysis was not available at the time of the filing. Once the full data set was available the company performed an effectiveness analysis using the same Method used for analyzing the

4.8kV hardening program and the Tree Trim program. The Company reviewed data for multiple groups, but the results of the effectiveness analysis were indeterminate due to the small sample size, driven by the short amount of time post-construction. All of the groups had a significant reduction in All Weather SAIDI, while the results for SAIDI ex-MEDs were more varied. These results are not sufficient for the Company to draw any conclusions from and indicate a larger sample size and more time is required to adequately determine the effectiveness of strategic undergrounding. Mr. Doel states that the Company requires the funding requested to complete its next pilot in order to obtain more data, which is the only way the Company will be able to determine if strategic undergrounding is a viable option. (2 TR 280-282.)

Staff still supports the full disallowance of the proposed pilot. As stated earlier, the Company did not follow the Commission's November 18, 2022, order in Case No. U-20836. Staff's hands are effectively tied on this issue.

**4. Staff recommends reducing demand side management capital expenditures by \$9,503,360.**

Staff recommends reducing demand side management capital expenditures by \$9,503,360, which reduces rate base by \$4,212,448. (Appendix E, Line 46, Col. b and f.) The specific exclusions are discussed below.

**a. Other Demand Response Programs and Pilots--  
Battery Energy Storage.**

Staff recommends reducing battery energy storage capital expenditures by \$1,990,360, which reduces rate base by \$1,271,941. (Appendix E, Line 44, Col. b and f.)

Staff witness Matthews summarized the Staff's position regarding the C&I Battery Storage Demand Response Pilot recommending, "the Company charged some portion of the battery cost to the participating customer given the number of benefits and the amount of potential savings the C&I customer may receive from this program." (7 TR 4564.) Mr. Matthews recommends a disallowance of one half of the program costs stating, "[b]ecause the Company is not planning to find the second participant until the first battery is installed and has given no timeline for when that second participant will be found, Staff recommends disallowing one half of the pilot expenses." (7 TR 4565.)

Staff asserts that charging participating customers, a portion of the potential savings would require several improvements in the pilot. First, given that the Company's proposal has no participation costs being paid for by the participating customer<sup>4</sup>, Staff avers that there is little incentive for participating customers to utilize the battery. Under Staff's proposal, participating customers will be able to utilize the battery to reduce demand charges and shift load away from peak times, which will allow them to utilize the benefit themselves and grid while also

---

<sup>4</sup> Exhibit S-15.1: Discovery response STDE-3.2i

recouping the participation costs. This incentive to utilize the battery is not the same for participating customers that have no costs to participate, as this arrangement has no costs to recoup through utilization of the battery and is not representative of a real-world program in which a customer would purchase and utilize the battery on site. Additionally, Staff sees a benefit in having a minimum number of events called each year to test the many functions of the battery. (7 TR 4565.)

Staff's recommendation to disallow half of the program costs (\$1,990,360 in the bridge period) stems from the fact that the Company currently has one customer identified and intends to find a second only after the installation is completed at the first customer site.<sup>5</sup> (7 TR 4565.) Given that the pilot costs are forecasted with two participating customers in mind, and the Company has not found a second, while also not providing a timeline for when a second will be found, it is reasonable to allow only half of the program costs.

In rebuttal, DTE Witness Keegan O. Farrell disagrees with Staff's disallowance stating, "[t]he Company plans for both batteries to be operational by the end of 2024. The Company continues to support recovery of the \$2 million proposed to be disallowed by Staff Witness Matthews." (5 TR 1330.) Mr. Farrell further disagrees with Staff's recommendation to charge a participation fee stating, "[t]he Company does not agree that a portion of the battery cost should be charged to the participating customer during the pilot period. The actual amount of savings

---

<sup>5</sup> Staff Exhibit S-15.0

a customer will receive is unknown and is one of the objectives of the pilot.” (5 TR 1331.)

While Staff is appreciative of the Company’s confidence in its pilot, the Company admits that a second participant has not been found yet stating, “[w]itness Matthews is correct that a second customer has not yet been identified, but the Company is working diligently to find one.” (5 TR 1331.) Given the lack of a second participant at the time of filing, and the freedom the Company has as to when it files its rate cases, Staff continues to support its recommendation to disallow half of the program costs give the uncertainty of finding a second participant. Staff continues to Stand by its recommendation to have participants pay a portion of the savings that result from this program as a participation fee. Staff acknowledges that while the savings are not known at this time, Staff described one possible methodology to ensure savings are realized by the participant and allow the Company to collect some of the costs of the program in return. Staffs recommended a methodology that would allow the participant and Company to split the savings generated by the customer. (7 TR 4564.) This methodology would ensure the participant is not paying more than the value they are realizing from participation and reduce the cost to all ratepayers. Given that a single customer is receiving nearly all the benefits of this program, it is reasonable for that customer to pay to participate in the program.

**b. DTE Insight Application**

Staff recommends reducing DTE Insight App capital expenditures by \$7,513,000, which reduces rate base by \$3,682,471. (Appendix E, Line 45, Col. b and f.)

The ALJ and the Commission should disallow the Company's total request for the DTE Insight Program. This includes \$4.78M in the 2021 historical year, \$2.06M in the bridge period, and \$0.67M in the test year ending 11/30/2024. (Rogers 7 TR 4664, Lines 16-18.)

The DTE Insight Program is a 9-year-old program, with investments beginning in 2014. The Company has recovered more than \$20M in rates from the previous four rate cases (U-18255, U-20162, U-20561, and U-20836) for the DTE Insight Program. Staff recommends the Company boost engagement and participation in the DTE Insight Application and supporting Energy Bridge device before investing more money in the program. (Rogers 7 TR 4665, Lines 1-3.) As Company witness Thac K. Nguyen states in testimony, only 233,384 households have authenticated DTE Insight downloads as of December 31, 2021. (Nguyen 5 TR 1273, Table 1.) That is about 10.6% of DTE's residential customers. Authenticated downloads do not guarantee use. According to DTE's 2022 Smart Grid Report, less than 5% of residential customers are actually using the DTE Insight Application annually.

In rebuttal testimony, Company witness Thac K. Nguyen stated that the Customer Data Downloads used in Staff's testimony are not from the Insight Program but from online usage. He adds that Staff's table shows that customers

are twice as likely to use the DTE Insight App than to view their usage information online. (Nguyen 5 TR 1280, Lines 12-21.) Further, since the Time of Day (TOD) rates went into effect in March 2023, the DTE Insight's weekly authentication average went from 646 per week before TOD to 2,702 per week nine weeks later. (Nguyen 5 TR 1281 Lines 1-4.) Despite the Company's arguments, Staff upholds its position. Even with the increase of weekly authentications due to TOD rates, a weekly rate of 2,702 is only 0.1% of DTE's residential customers and, once again, authentication does not guarantee use. That is very insignificant given the past large investment and the requested continued investment in this program. Staff would expect a substantially higher number of users before more of an investment is prudent.

Regarding the Energy Bridge devices (EBs), 38,093 households have authenticated Energy Bridges as of December 31, 2022. That is 1.7% of DTE's total residential customers. (7 TR 4665, Lines 9-11.) Company witness Thac K. Nguyen states there are 55,468 Energy Bridges in inventory as of December 31, 2022, and the capital expenditures requested includes future purchases of Energy Bridge devices. (Nguyen 5 TR 1277, Table 2, and Lines 11-15.) Staff asserted in testimony that with a device usage growth rate of 0.18% per year, more Energy Bridges will not be necessary for many years. (Rogers 7 Tr 4666, Lines 3-4.)

In rebuttal testimony, Company witness Thac K. Nguyen disagrees with Staff's \$4.8M adjustment for the historical year's spending on 30,000 Energy Bridge devices because the Commission approved recovery of the costs in Case Number U-

20836. Company witness Thac K. Nguyen states DTE anticipated the pace of requests for Energy Bridge devices to be greater, however there is still an increase in participation, and it still expects to see all the EB devices in inventory utilized. (Nguyen 5 TR 1281, Lines 7-15.) Staff argues that the EB devices bought in 2021 were unnecessary and the Company should have known better than to purchase them at that time. There was no indication in the Company's past two applications, nor in the instant case, that participation would increase so drastically that the additional EBs were essential at that time. In Case Number U-20561, the testimony of Company witness R. Cejas Goyanes projected a purchase of 20,000 Energy Bridge devices in 2021. (Goyanes 9 TR 3537, Lines 18-20.) The Company estimated 83,492 EBs in the field as of April 30, 2021, resulting in a planned 23,619 EBs in inventory. (Goyanes 9 TR 3538, Table 7.) In Case Number U-20836, the Company had actual data for 2020 and as of December 31, 2020, there were only 50,517 EBs in the field, significantly less than even anticipated for 2021. This left 36,594 EBs in inventory at the end of 2020. In that case, testimony showed 40,000 EBs were purchased by October 31, 2021, though only 7,000 participants were added between December 31, 2020, and October 31, 2021. Though the Company had not seen such growth before, they estimated an additional 40,000 EB participants between 2022 and 2023. (U-20836 Nguyen 7 TR 1610, Table 2.) In the instant case, DTE's participation projections have slowed, however, planned data as of November 30, 2024, estimates 44,308 EBs in inventory. (5 TR 1277, Table 2.) This shows the 40,000 purchased in 2021 may not be used even by the end of 2024.

For this reason, the \$4.8M spend on Energy Bridge devices in 2021 was unnecessary. These devices are still not used, nor are they useful sitting in inventory. And it would also be imprudent to purchase additional Energy Bridge devices in the bridge and/or test years.

Consequently, it is unreasonable for the Company to continue investing ratepayer dollars on the DTE Insight Program until engagement and participation in the DTE Insight Application and usage of the Energy Bridge have significantly improved. The ALJ and the Commission should disallow \$4.78M in the 2021 historical year, \$2.06M in the bridge period, and \$0.67M in the test year ending 11/30/2024.

**5. The Commission should reduce the Company's information technology capital expenditures by \$77,252,206.**

The Commission should reduce the Company's information technology capital expenditures by \$77,252,206, which reduces rate base by \$43,861,360. (Appendix E, Line 73, Col b and f.) Staff addresses its specific recommended disallowances in more detail below.

To begin, the ALJ and the Commission should disallow \$6.7M in the historical period ending 12/31/2021, \$28M in the bridge period ending 11/30/2023 (\$3.72M in the 12 months ended 12/31/2022 and \$24.28M in the 11 months ending 11/30/2023), and \$42.54M in the test year ending 11/30/2024 in total IT capital expenditures, as well as \$47.95M in total IT O&M expenditures. (Rogers 7 TR 4652,

Lines 4-9.) This disallowance is made up of IT projects with Level 2 cost estimates, individual IT projects, and projected O&M expenses.

**a. Capital expenditures for Plant and Field IT should be reduced by \$836,213. (Appendix E, Line 52.)**

Staff, through its witness, Nicholas Evans, recommends downward adjustments to the following information technology (IT) projects: the Supervisory Control and Data Acquisition (SCADA) System Improvement project, the ESRI Application Health Project, and the DTE Electric Utility Network Project. (7 TR 4417.)

The SCADA System Improvement project seeks to adhere to regulatory and security standards, and the project will seek to apply the latest vendor updates. The Company is projecting \$520,000 in capital expenditures for 2022, 2023 and 2024, which pro-rates to \$476,667 for the 11 months ending November 30, 2023, and \$520,000 for the test year.

The ESRI Application Health project supports enhancements to the Company's automated mapping system that supports all GPS mapping data including operating maps and customer-facing outage maps. The Company is projecting \$380,000 in capital expenditures for 2022, and \$440,000 in capital expenditures for 2023 and 2024. This pro-rates to \$403,333 for the 11 months ending November 30, 2023, and \$440,000 for the test year.

The DTE Electric Utility Network Project implements the new ESRI UN product in the cloud. The Company is projecting \$375,000 in capital expenditures

for 2023 and 2024, which pro-rates to \$343,750 for the 11 months ending November 30, 2023, and \$375,000 for the test year. (7 TR 4417-4418.)

For the SCADA System Improvement project, Staff witness Nicholas Evans recommends downward adjustments of \$134,904 for the 11 months ending 11/30/2023 and \$147,168 to the test year. (7 TR 4418.) As stated earlier, the Company is projecting \$520,000 in capital expenditures for 2022, 2023 and 2024. Staff's position is that, by virtue of the three projected amounts being identical, said projections are likely preliminary and the actual expenditure amounts could be different. Mr. Evans therefore averaged the actual spending from 2019 through 2022, shown in Staff Exhibit S-14.1, p 3, to come up with a historic average of \$372,832, which would have an 11-month pro-rated amount of \$341,763. Mr. Evans then calculated the difference between the pro-rated capital projection of \$476,667 for the 11 months ending November 30, 2023, and the 11-month historic average of \$341,763 to find a downward adjustment of \$134,904 for the 11 months ending 11/30/2023. Next, he calculated the difference between projected \$520,000 for the test year and the historic average of \$372,832 to find a downward adjustment of \$147,168 to the test year. (7 TR 4418-4419.)

For the ESRI Application Health project, Staff witness, Nicholas Evans, recommends downward adjustments of \$93,149 for the 11 months ending 11/30/2023 and \$101,617 to the test year. (7 TR 4418.) As stated earlier, the Company is projecting \$440,000 in capital expenditures for 2023 and 2024. Staff's position is that, by virtue of the two projected amounts being identical, said

projections are likely preliminary and the actual expenditure amounts could be different. Mr. Evans therefore averaged the actual spending from 2019 through 2022, shown in Staff Exhibit S-14.2, p 3, to come up with a historic average of \$338,383, which would have an 11-month pro-rated amount of \$310,184. Mr. Evans then calculated the difference between the pro-rated capital projection of \$403,333 for the 11 months ending November 30, 2023, and the 11-month historic average of \$310,184 to find a downward adjustment of \$93,149 for the 11 months ending 11/30/2023. Next, he calculated the difference between projected \$440,000 for the test year and the historic average of \$338,383 to find a downward adjustment of \$101,617 to the test year. (7 TR 4419.)

For the DTE Electric Utility Network Project, Staff witness Nicholas Evans recommends downward adjustments of \$171,875 for the 11 months ending 11/30/2023 and \$187,500 to the test year. (7 TR 4418.) As stated earlier, the Company is projecting \$375,000 in capital expenditures for 2023 and 2024. Staff's position is that, by virtue of the two projected amounts being identical, said projections are likely preliminary and the actual expenditure amounts could be different. However, as shown in Exhibit S-1 14.3, page 2, there is no historical spending associated with this project. Mr. Evans therefore applied a 50% reduction to the \$343,750 pro-rated amount for the 11 months ending November 30, 2023, and to the \$375,000 for the test year. This results in downward adjustments of \$171,875 for the 11 months ending 11/30/2023 and \$187,500 to the test year. (7 TR 4419-4420.)

Staff will recommend recovery of incurred IT expenditures in future rate cases if Staff finds the expenditures to be reasonable and prudent. (7 TR 4420.)

Company witness Pankaj Sharma states that the similarity in cost annually for the Supervisory Control and Data Acquisition (SCADA) System Improvement Project, the ESRI Application Health Project, and the DTE Electric Utility Network Project reflect a planned schedule of spend with the allocated resources to deliver. For the SCADA System Improvement Project in 2019 there was a Company-mandated freeze put in place for any change impacting the Company's old EMS system, a SCADA component, which eliminated any development for this asset, and as a result the Company neither forecasted nor included any spend on this area for that year and returned to full spend the following year. Therefore, the Company claims the use of 2019 data in the average is misleading. For the ESRI Application Health Project, investments were put on hold while supporting the overall ESRI Upgrade Project to mitigate the risk of discontinued GIS support with v10.2.1. Once the ESRI platform was updated to a supported version and retained GIS support, the Company returned to regular operations and continued investment planned for the system. (5 TR 2055-2058.)

Staff still recommends the reduction for the Supervisory Control and Data Acquisition (SCADA) System Improvement Project, the ESRI Application Health Project, and the DTE Electric Utility Network Project. Staff's position is that, by virtue of the projected amounts being identical, said projections are likely preliminary and the actual expenditure amounts could be different. Using a

historic average is a reasonable methodology to forecast how much capital expenditure associated with these projects should go into rates. The Company can always request recovery of capital expenditures above the amounts included in rates in a future rate case, and Staff will recommend recovery of those expenditures if they are found to be reasonable and prudent.

**b. Capital expenditures for Customer Service IT should be reduced by \$17,570,000. (Appendix E, Line 58.)**

The Commission should disallow all costs related to the PrePay and PrePay Phase II projects due to the material changes made to these pilots from the pilot as presented in Case No. U-21087, the lack of proven customer support or interest in such programs, and the high cost involved with these projects. This represents a total of \$9.3 million in capital costs, with \$6,704,000 for PrePay during the historical period ending 12/31/2021, and \$2,640,000 during the test year ending 11/30/2024 for the PrePay and PrePay Phase II projects. .

As stated in Staff's direct testimony, Staff has concerns with the requirements of both PrePay pilots, as the enrollment numbers were capped at 3,000 customers, a dramatic change from the pilot as presented in Case No. U-21087, which proposed to enroll 3,000 customers in the first year of its PrePay pilot and was targeting to enroll up to 40,000 customers during the program's first five years. (7 TR 4555.) In addition, the total arrears threshold for eligible customers was \$750 in Case No. U-21087, while the threshold has been lowered to just \$250 in the instant case. (*Id.*) In its rebuttal, the Company notes that it met with Staff

prior to filing the instant case and provided Staff with an overview of the most significant changes being proposed for the PrePay pilots. (Hatsios 5 TR 1784.)

While it is true that Staff did meet with the Company and heard details about the PrePay pilots as presented in the instant case, it is irrelevant if the Company notified Staff in a meeting not on the record about details of the PrePay pilots, as only the case as filed and presented on the record is relevant. Staff's awareness of what the Company plans to file in a rate case does not equal consent to or support of things the Company does indeed present in its rate cases.

The Company notes in its rebuttal testimony that the parameters of the PrePay pilots were changed in response to the concerns of intervenors who filed testimony in Case No. U-21087. (*Id.* at 1786.) Intervenors do not speak for or represent Staff's opinions and any changes the Company made due to Intervenors' wishes do not necessarily reflect those of Staff and Staff is not beholden to them. As stated in Staff's direct testimony in the instant case, Staff has serious concerns about the lowered threshold for both enrollment and arrearages amounts for the PrePay pilots presented in this case, and questions how many and what types of customers could realistically benefit from the programs as presented. That the Company states in its rebuttal that it is "open to discussing an increase in the number and pace of enrollments with Staff prior to the implementation of an approved PrePay Pilot" does not alleviate Staff's concerns; as stated before, the program's changes and parameters must be presented in the filed case and on the record, not made during off-the-record meetings between Staff and the Company.

(*Id.*) What the Company proposes in rebuttal is reliant on potential changes that *may* happen in the future and is not something Staff can support.

Staff maintains its concerns, as expressed in direct testimony, that the Company has failed to seek out current and relevant customer interest in PrePay programs. Indeed, in its rebuttal testimony, the Company notes that it relied on the 2020 customer focus group—consisting of just 28 customers—and a 2019 industry survey to gauge customer interest in such programs. (*Id.* at 1789.) The Company also states that it used information ascertained from its previous prepaid billing pilot, discussions with other utility providers, and participation in industry prepay consortiums to measure customer interest in a prepay program. (*Id.* at 1790.) Again, Staff has serious reservations with both the timeliness and relevance of those methods used by the Company, as the previous prepay pilot the Company offered was in place from 2011-2015, and the learnings from that pilot are available in a report from 2014. (*Id.*) As stated in direct testimony, Staff does not believe that a report generated nine years ago has much relevance to helping seek customers' interest today in a prepay program. While it may be useful for the Company to consult with other utility providers regarding prepay programs, those other providers do not represent the Company's actual customer base and, again, do not demonstrate to Staff that DTE's customers are interested in a prepay program at this time.

As stated in Staff's direct testimony, Staff also has concerns with the high costs involved with the presented PrePay pilots. In its rebuttal, the Company

stated that \$4.4 million of the programs' costs have been depreciated, which is being borne by DTE shareholders. (*Id.* at 1786.) According to the Company, this will reduce the costs to ratepayers through revenue recovery to approximately \$2.3 million. (*Id.*) Despite the apparent overall reduction in the costs for these pilots, dividing the total cost of the projects by the maximum number of customers who may be enrolled in PrePay—3,000—comes out to a cost of approximately \$767 per enrolled customer. That is a very steep amount of money to pass onto the Company's ratepayers and Staff cannot support it. Staff is also wary of the stated additional capital required to enhance the PrePay program and does not take the Company at its word that those costs are expected to be "minimal." (*Id.* at 1787.) Staff has no proof that those additional capital costs will, indeed, be minimal and cannot rely on mere predictions.

For all the foregoing reasons, the Commission should disallow all costs requested for both the PrePay and PrePay Phase II pilots. Until the Company can decisively prove current customer interest, allow for a larger pool of customers to utilize a prepay program, and present a prepay program at a reasonable and prudent cost, Staff cannot support such a program.

- c. The Commission should disallow all capital costs requested for the Changing Bill Size project, representing a total of \$900,000,675,000, with \$731,000,548,250 in the bridge period ending 11/30/2023 and \$169,000,126,750 in the test year ending 11/30/2024.**

The Commission should disallow all costs associated with the Changing Bill Size Project because the costs being requested for it are costs that should not be passed on to ratepayers. As stated in Staff's direct testimony, Staff believes that the Company's wish to standardize the paper size on which it prints customers' bills is one that the Company should resolve themselves, without passing the costs along to ratepayers. (Klocke 7 TR 4548.) The Company chose their current paper supplier and chose to print their bills on that paper, and Staff is not persuaded that switching the paper or paper suppliers would result in any true cost savings for customers. In rebuttal, the Company responded that "quantifiable benefits" would be derived from making the switch to a standard sized paper would reduce the cost of printed bills "by approximately \$300,000 per year," yet this project's overall requested costs far exceed the potential cost savings it could provide. (Hatsios 5 TR 1783.) Simply put, Staff is not convinced that the costs involved with this project will produce real, tangible savings for DTE's customers, and thus cannot approve those costs as they are neither reasonable nor prudent.

- d. The Commission should disallow all capital costs requested for the Customer Service Sales & Service project, representing \$7,326,000,549,500 for the test year ending 11/30/2024.**

In direct testimony, Staff recommended full disallowance of the Customer Service Sales & Service Project. This represents a total disallowance of \$7,326,000 in capital costs for the Test Year ending 11/30/2024, as well as \$330,000 in O&M costs for the Test Year. (Klocke 7 TR 4549.) In its rebuttal testimony, the Company

did not respond to or rebut Staff's position and Staff maintains its original position in recommending full disallowance of all costs associated with the Customer Service Sales & Service Project.

**e. Capital expenditures for Oracle Forecasting Tool should be reduced by \$3,800,000. (Appendix E, Line 60.)**

The ALJ and the Commission should disallow \$3.61M in the bridge period ending 11/30/2023 (\$2.8M in 2022 and \$0.81M in the 11 months ending 11/30/2023), and \$0.19M in the test year for the Oracle Forecasting Tool (Rogers 7 TR 4657, Lines 9-12) Staff also recommends a disallowance of \$6,250 in O&M expenses. The Company has not justified the benefit of the project in comparison to the cost. Company testimony indicates that the Oracle Forecasting Tool is estimated to reduce the forecast cycle time by 2000 hours a year. (Sharma 5 TR 1855, Lines 8-10.) The fully loaded hourly rate of an employee who performs this task is \$83.31. (Exhibit S-12.7, p 1). This equates to a savings of \$166,620 per year. (Rogers 7 TR 4657, Line 19.) The \$3.8M cost of this project far exceeds the \$166,620 benefit. Without the implementation of this investment, the task is still being accomplished manually.

In rebuttal, the Company restated its direct testimony and argued that cost savings is not the only benefit of this project. It argues that the project also increases productivity and efficiency by reducing human errors and avoiding program delays. Further, it states that other solutions were evaluated and the

alternative to the Oracle Forecasting Tool was much more expensive and would cost more in annual maintenance. (Sharma 5 TR 2053, Lines 2-23.)

Staff maintains its position. Staff has the responsibility of ensuring costs passed onto ratepayers are reasonable and prudent. A project with so little savings in comparison to the cost is not a prudent investment. Staff recommends the Company continue performing the tasks as usual and continue to search for a more practical solution. Therefore, the ALJ and the Commission should disallow the \$3.61M in the bridge period ending 11/30/2023, \$0.19M in the test year and \$6,250 in O&M requested for the Oracle Forecasting Tool.

**f. Capital expenditures for Infrastructure Automation Maturity IT should be reduced by \$406,000. (Appendix E, Line 61.)**

The ALJ and the Commission should disallow \$0.41M in the test year for the Infrastructure Automation Maturity Project. (Rogers 7 TR 4658, Lines 15-16.) Staff also recommends a disallowance of \$34,370 in O&M expenses. While this investment might be nice to have, however it is not a necessity and is an imprudent expense to pass onto ratepayers. The Company provided no evidence in testimony of how this project will increase safety or reliability, nor any cost savings. The tasks associated with this project will still be completed manually. (Sharma 5 TR 1974, Lines 4-6.) Additionally, when the qualitative and quantitative benefits of this project are evaluated according to the weighted categories of strategic alignment, customer experience, employee engagement, affordability and growth, benefit/cost, operational reliability, and foundational capability, it received a project

prioritization score (PPS) of 3.7 on a scale of 1-9. (Sharma 5 TR 1824, Figure 2.) To Staff, this indicates that this investment aligns with a couple of the PPS categories and may have some impact, however the impact will not be large or significant.

In rebuttal testimony, Company witness P. Sharma referred to his direct testimony and stated that automating the current manual process will help “reduce the consumption of resources at DTE Electric” and is therefore a prudent investment. (Sharma 5 TR 2054, Lines 10-13.)

Staff maintains its position. The Company did not provide any evidence of how this project will increase safety or reliability or provide cost savings. The statement that the investment would help reduce the consumption of resources is not supported by any quantifiable data. As a result, there is no proof this investment will benefit ratepayers. If this investment is automating manual tasks, ratepayers should surely see a cost savings. For this reason, the ALJ and the Commission should disallow the requested \$0.41M in the test year, and \$34,370 in O&M for the Infrastructure Automation Maturity project.

**g. Capital expenditures for Infrastructure Operations Center Automation IT should be reduced by \$406,000. (Appendix E, Line 62.)**

The ALJ and the Commission should disallow \$0.41M in the test year for the IOC Automation project. (Rogers 7 TR 4660, Lines 7-8.) Staff also recommends a disallowance of \$34,370 in O&M expenses. Like the Infrastructure Automation Maturity Project, this investment might be nice to have, however it is not a

necessity and is an unjustified expense to pass on to ratepayers. The Company provided no evidence of cost savings ratepayers will receive.

In rebuttal testimony, Company witness P. Sharma referred to his direct testimony, claiming that cost benefit is not the only reason for this investment as it also offers operational reliability improvements. (Sharma 5 TR 2055, Lines 1-2.)

Staff maintains its position. The IOC Automation project has a PPS of 3.6 on a scale of 1-9. This indicates to Staff that the impact on the Company's strategic alignment, customer experience, employee engagement, affordability and growth, benefit/cost, operational reliability, and foundational capability is not large or significant. (Sharma 5 TR 1824, Figure 2.) Staff is perplexed that critical remote telecom sites with a possibility of "fire due to high heat, or other damage in these rooms—resulting in long period of communications loss and potential catastrophic damage" (Sharma 5 TR 1975, Lines 5-6) are unmonitored and that the solution to this risk only garners a 3.6 PPS score. If this project was truly important for monitoring "critical" remote locations, improving reliability, and preventing "catastrophic" damage, it would receive a much higher PPS score. As a result, the Commission and the ALJ should disallow \$0.41M in the test year and \$34,370 in O&M for the IOC Automation project.

**h. Capital expenditures for Information Technology Level 2 Cost Estimates should be reduced by \$54,233,993. (Appendix E, Line 71.)**

The ALJ and the Commission should disallow \$0.92M in the 12 months ending 12/31/2022, \$22.34M in the 11 months ending 11/30/2023, \$30.97M in the

test year ending 11/30/2024, and \$3.15M in O&M for 124 unique IT projects (210 business cases) with Level 2 cost estimates. (Rogers 7 TR 4653, Lines 2-6.) Level 2 cost estimates are incomplete and indefinite in nature. While the Company stated through audit that they are using a new application to help move IT project requests through the Annual Planning Cycle (APC) and cost estimation process, they do not admit any changes to their cost estimation methodology or how Level 2 cost estimates are derived since their previous electric rate case, Case Number U-20836. (Staff Exhibit S-12.4, pp 4-5.) In Case Number U-20836, the Company stated Level 2 cost estimates are based on internal labor hours, hardware costs, software costs, any internal project management costs, and vendor quotes. (U-20836 Sharma 7 TR 1928 Lines 17-20). However, these projected costs still lack a definite scope and schedule. Projects are assigned a Level 2 cost estimate more than a year before planned implementation. Projects with Level 2 cost estimates are not under contract and many things can change in the time before execution such as a change in project scope, prioritization within the APC, vendor quote, and the necessity of the project altogether. Company Witness Sharma rebuts Staff's claims in testimony that Level 2 cost estimates are obtained prior to comprehensive review. He states that Level 2 cost estimates are comprehensive by cost type and phase and are supported by the IT architecture team. (Sharma 5 TR 2049, Lines 5-11.) Staff argues that Figure 1 DTE IT APC Cadence in Company testimony shows that a Level 2 estimation is built under the Detailed Estimate phase, however, additional reviews for the project are conducted in the Pending Approval phase,

prior to formal approval. (Sharma 5 TR 1822, Figure 1.) Staff interprets this to mean that a project's review is therefore not complete prior to a Level 2 estimation assignment but undergoes further review after the cost estimate is assigned.

Staff believes the level of cost information provided by the Company best correlates to the AACE Class III Estimate, with semi-detailed unit costs. The AACE Class III Estimate has a lower bound of -20%. In rebuttal, the Company argues that the AACE Class III Estimate also has an upper bound of 30% and that Level 2 cost estimates more closely align with the AACE Class II Estimate, which has a lower bound of 15%. Staff chose a 20% adjustment to projects with Level 2 cost estimates because that is what the Company could over recover from these projects. Staff's argument is similar to its argument for the disallowance of contingency. The Company chooses to file an application with a projected test year and has the opportunity to over recover for these projects. Alternatively, the Commission does not have the ability to perform retroactive ratemaking and correct the issue if the full cost estimate is not spent. If the Company spends more than 80% of the projected cost, it can include the updated information in the next electric rate case to be reviewed for reasonableness and prudence.

In testimony, Staff filed Exhibit S-12.5 showing the percent difference in projected cost estimates of business cases with Level 3 cost estimates in the instant case that were previously classified as Level 2 cost estimates in Case Number U-20836 to demonstrate the imprecision of Level 2 cost estimates. Staff calculated the percent difference to range from -148% to 142%. (Exhibit S-12.5, Line 105.) In

rebuttal testimony, the Company stated that Staff's exhibit "does not account for the complete picture based on historical data". (Sharma 5 TR 2050, Lines 2-3.)

Further, the Company used Staff's exhibit to provide Table 1 showing the number and percentage of projects, out of 103, with estimated cost differences less than 10%, between 10% and 20%, and greater than 20%. (Sharma 5 TR 2050, Table 1.)

The Company argues that approximately 61% of projects had less than a 10% variation in the Level 2 and Level 3 cost estimates. It also argues that a 20% disallowance is speculative as it "exceeds the spend variance projected". (Sharma 5 TR 2051 Lines 15-16). Staff does not find this argument convincing. While 61% of the projects had Level 2 and 3 cost estimates within 10%, 39% did not. Only 5% of projects had Level 2 and 3 cost estimates between 10% and 20%. Most importantly, 34% of projects had Level 2 and 3 cost estimates that varied by greater than 20%. This 20% should not be construed as an average of underspend. In fact, these cost estimate differences vary from 20% to 148%. This means that the Company could over recover by up to 148% from more than a third of these 103 projects. Staff believes that, taking into consideration how large the lower bound goes in the cost estimate difference between formerly Level 2 and now Level 3 cost estimates, a 20% disallowance is a conservative adjustment, as many of the cost estimate differences are significantly beyond that. For this reason and those discussed above, the ALJ and the Commission should disallow 20% of the requested expenses for the IT projects with a Level 2 cost estimate. This totals \$0.92M in the 12 months ending

12/31/2022, \$22.34M in the 11 months ending 11/30/2023, \$30.97M in the test year ending 11/30/2024, and \$3.15M in O&M.

**6. The Commission should reduce the Company's corporate staff capital expenditures by \$1,341,667.**

The Commission should reduce the Company's corporate staff—NERC critical infrastructure program (Exhibit A-12, B5.8, p 1, line 6) other Miscellaneous capital expenditures by \$1,341,667, which reduces rate base by \$833,685. (Appendix E, Ln 77, Col b and f.)

In its direct testimony, Staff recommended the Commission disallow capital expenditures for Company Exhibit A-12, B5.8, page 1, line 6 of \$641,667 in the 11-month projected bridge period prior to the test year, ending November 30, 2023, and \$700,000 in the projected test year. (7 TR 4334.) Testimony from Company Witness Theresa Uzenski stated that in 2023 and 2024 the company expected to spend \$2 million dollars per year on the NERC critical infrastructure program. (5 TR 1533.) In audit, the Company informed Staff that no NERC specific projects had yet been planned for these years. (Staff Exhibit S-18.0.) Staff preceded its analysis by asking the Company how they arrived at the \$2 million per year estimate for 2023 and 2024, to which the Company stated that “the \$2 million is a high-level estimate” and “for reference, the Company spent \$1.2M and \$1.3M on NERC/CIP compliance projects for 2020 and 2021, respectively”. In testimony Staff reasoned that while complying with NERC/CIP was necessary, the Company had not adequately justified future spending increases. Therefore, Staff recommended

an adjustment from \$2 million to \$1.3 million per year, in line with the Company's historical spend. (7 TR 4335.)

The Company provided no rebuttal testimony relating to these recommended adjustments. The Commission should disallow capital expenditures for Company Exhibit A-12, B5.8, p 1, line 6 of \$641,667 in the 11-month projected bridge period prior to the test year, ending November 20, 2023, and \$700,000 in the projected test year.

**7. The Commission should reduce the Company's charging forward capital expenditures by \$4,930,000.**

The Commission should reduce the Company's charging forward capital expenditures by \$4,930,000, which reduces rate base by \$2,414,669. (Appendix E, Ln 82, Col b and f.)

*Charging Hubs Proposal*

Staff is against DTE Electric's Charging Hubs proposal. (7 TR 4431.) In its prior rate case, the Commission approved two Charging Hubs designed for medium- and heavy-duty vehicles. In this case, the Company is requesting to increase the level of spending to \$4.0 million in the projected test year. (Exhibit A-12, Schedule B5.9, page 4, line 6, columns (e) and (f).) The spending will allow DTE Electric to complete the initial two Charging Hubs and begin the construction of a third.

Staff is against the increase. The initial two Charging Hubs have not been built yet and it is impossible to learn anything. There is not any justification to building a third Charging Hub. (7 TR 4431.) It is too speculative at this time.

Staff's initial support of the Charging Hubs was based on the potential lessons to be learned, both for the Company's and other potential market players' benefit.

Absent those lessons, and the resultant impact on the potential market for such hubs, additional hubs should not be funded by ratepayers. (7 TR 4431.)

Staff recommends a \$1.33 million disallowance. Given the \$4.0 million request is for three hubs, the Company should only get funding to cover the previously approved two Charging Hubs—\$2.66 million dollars. (7 TR 4431.)

#### *Community Charger Program*

Staff recommends disallowing the entire proposal. (7 TR 4432.) Under the Community Charger Program, DTE Electric would build, own, and operate, and maintain up to 360 Level 2 chargers. These chargers would be located in public parking lots, including curbside installations such as utility pole-mounted and streetlight-mounted chargers. The program's focus would be on locations that provide publicly available overnight parking to provide affordable charging options to residents of multiuser dwellings that do not have the ability to install a charger and enroll in a TOD rate. Further, the Company commits to investing a minimum of 40% of funding for Community Chargers in rural areas or Disadvantaged Communities. DTE Electric is requesting \$3.6 million for the projected test period. (Exhibit A-12, Schedule B5.9, page 4, column (f).) The Company is requesting capital treatment.

Staff recommends disallowing the full \$3.6 million. (7 TR 4432.) DTE Electric should not own and operate EV charging infrastructure. (7 TR 4432). It

restricts competition and inhibits innovation. Additionally, it places risk on the ratepayers. Exceptions should only be granted judiciously after thorough scrutiny. Exceptions should be limited to remedying major market failures. The Community Charger Program does not pass this test and should therefore be disallowed.

**8. The Commission should reduce the Company's contingency capital expenditures by \$14,040,000.**

The Commission should reduce the Company's contingency capital expenditures by \$14,040,000, which reduces rate base by \$12,985,500. (Appendix E, Ln 88, Col b and f.)

The ALJ and the Commission should disallow all contingency expenditures included in the Waterford Service Center Project, ASOC, and Blue Water Energy Center, totaling \$12.98M in the 11 months ending 11/30/2023 and \$1.06M in the test year. (Rogers 7 TR 4649, Lines 8-9.) In its application, the Company requested recovery of \$3.94M in the 11 months ending 11/30/2023 and \$0.46M in the test year ending 11/30/2024 for the Waterford Service Center Project, \$2.84M in the test year ending 11/30/2024 for the ASOC, and \$6.2M in the 11 months ending 11/30/2023 and \$0.6M in the test year ending 11/30/2024 for the Blue Water Energy Center Project. (Staff Exhibit S-12.2, p 3.) The Company did not file rebuttal testimony refuting Staff's recommendation for the disallowance of contingency expenditures related to the Waterford Service Center Project.

Regarding the ASOC, the Company stated in rebuttal testimony its agreement with Staff that the associated contingency should be removed, adding it

will follow Staff witness Danielle R. Rogers' recommendation if the need for the funds arise and support its justification and prudence in a future rate case to be analyzed for recovery at that time. (Andahazy 3 TR 608, Lines 9-12.)

Concerning the Blue Water Energy Center, Company witness J. L. Morren indicated that Staff double counted the contingency adjustment, however he did not support his statement further. (Morren 5 TR 2423, Lines 13-17.) Staff witness Jonathan J. DeCooman recommended an \$8.1M disallowance in the 2021 historical year and Staff witness Danielle R. Rogers recommended a disallowance of \$6.8M in the 2023 bridge and 2024 test years. (Rogers 7 TR 4650, Lines 1-3.) These proposed disallowances are very different. Staff witness DeCooman's \$8.1M disallowance in 2021 is past contingency that has not been resolved. (See section III.B.1.c.i. of Staff's brief.) Staff witness Danielle R. Rogers' \$6.8M disallowance is forward facing contingency to be used, if necessary, in the future 2023 and 2024 time period.

Contingency expenditures are costs budgeted beyond the base estimate in case unpredicted or unforeseen events occur. While this is important for budgetary purposes, if the expenses are currently unknown, Staff is unable to review them for reasonableness and prudence. Further, these costs may not be spent in full or at all, proving them inappropriate to pass onto ratepayers at this time. If these expenses are eventually incurred, Staff recommends the Company support them in a future rate case where they can be reviewed that they were justly and sensibly spent.

Contingency expenditures have been consistently disallowed by the Commission in the Company's general electric and gas rate cases including DTE's last decided rate case, Case Number U-20836, as well as Case Numbers U-20940, U-20162, U-18014, and U-17767. Therefore, the ALJ and the Commission should disallow recovery of contingency expenditures in the Waterford Service Center Project, the ASOC, and the Blue Water Energy Center Project. This consists of \$12.98M in the 11 months ending 11/30/2023 and \$1.06M in the test year ending 11/30/2024.

#### **IV. Capital Structure and Rate of Return**

##### **A. Cost of Capital**

In its initial filing, the Company requested an overall cost of capital of 5.70% (5 TR 2592) with a return on equity (ROE) of 10.25%. (5 TR 2954.) Staff witness Joseph Ufolla sponsors Staff's cost of capital position, recommending a lower cost of capital of 5.52%. (7 TR 4703.) Staff recommends a ROE range of 9.30%-10.30% and used 9.80% as its recommended ROE in its overall cost of capital determination. (7 TR 4705) Staff relied on the guidelines set forth by the Supreme Court in the *Hope* and *Bluefield* decisions in determining a reasonable ROE for DTE Electric. (7 TR 4706.) Likewise, the Attorney General and ABATE recommended lower overall cost of capital and ROE figures as well. The Attorney General suggests an overall cost of capital of 5.52% with a ROE recommendation of 9.80%. (6 TR 3728.) ABATE recommends a ROE range of 9.20%-9.90% with a point estimate of 9.55%. (4 TR 1154.) ABATE does not explicitly support a numerical overall cost of capital. Staff

maintains its recommendation of a 5.52% overall cost of capital, and the Commission should approve Staff's recommendation based on the reasoning provided below.

### **B. Capital Structure**

Staff did not dispute the Company's recommended balances for long-term debt, equity, short-term debt, preferred stock, job development investment tax credits, or net deferred income tax. Additionally, Staff did not dispute the Company's recommended cost rates for long-term debt, short-term debt, preferred stock, job development investment tax credits, or net deferred income tax. Staff recommends the Commission approve its capital structure with a 50% equity ratio. (7 TR 4704.)

### **C. Return on Equity**

Staff witness Joseph Ufolla sponsors Staff's return on equity testimony. Staff recommended a ROE range of 9.30% to 10.30% and used 9.80% as its recommended ROE in its overall cost of capital determination. (7 TR 4705.) Staff relied on the guidelines set forth by the Supreme Court in the *Hope* and *Bluefield* decisions in determining a reasonable ROE for DTE Electric. (7 TR 4706.) Since DTE Electric is not publicly traded, Staff used a group of eleven publicly traded electric utility companies to help establish a reasonable cost of equity range for the Company. Staff used five criteria to establish its proxy group; a proxy company must: 1) be listed as an Electric Utility by Value Line; 2) have a full Value Line report

available; 3) be currently paying dividends to shareholders; 4) must not be the target of a merger or acquisition; and 5) must have a Moody's credit rating of Baa1 or higher. (7 TR 4707.) The proxy group's statistics were used to provide a reasonable approximation of the Company's required cost of equity in Staff's DCF and CAPM cost of equity models; additionally, Staff relied on a risk premium analysis and a review of other state commission ROE decisions to help reach a recommended cost of equity for DTE. (7 TR 4705.)

The Company's cost of capital witness, Dr. Bente Villadsen, sponsored DTE's 10.25% ROE recommendation. (5 TR 2954.) Dr. Villadsen submitted rebuttal disputing certain portions of Staff's ROE analysis and 9.80% recommendation. Additionally, the Attorney General recommends a ROE of 9.80% (6 TR 3728) and ABATE recommends an ROE of 9.55%. (4 TR 1154.)

#### **D. Discounted Cash Flow model (DCF)**

The DCF model assesses those investors value stocks by 'discounting' expected future cash flows, attributed to securities, to present day. This 'discounting' process applies a capitalization rate to the future cash flows, both dividends and capital gains.

Staff obtained the data for its DCF analysis using statistics from its proxy group and growth estimates from industry experts. Staff's DCF analysis yielded an average ROE estimate of 9.74%. (7 TR 4710.) The AG and ABATE performed their own DCF analyses as well. The AG's models indicated an average required ROE of 9.33%. (6 TR 3739.) ABATE provided multiple DCF analyses culminating in a

summary of these models being approximately 9.20%. (4 TR 1189.) DTE also provided multiple DCF analyses with outputs of 8.9% and 10.7% but rejects the lower of the two outputs because it is “out of line with other results.” (5 TR 2992.)

Staff’s testimony also addressed the Company’s DCF analysis and ROE estimate. Staff disagreed with the Company’s use of gas utilities in its proxy group which were utilized in this analysis and therefore only considered the Company’s “Electric Sample.” (7 TR 4707-4708.) Additionally, Staff disagreed with the Company’s implementation of an Overall Cost of Capital adjustment, better known as the After-Tax Weighted Average Cost of Capital (ATWACC) approach, to adjust its DCF results. (7 TR 4711.) The ATWACC approach used by the Company has not been historically relied upon by the Commission; more importantly, due to a fundamental difference between how market equity and book equity values are calculated, the ATWACC approach most always results in a higher ROE output than a DCF analysis without this adjustment. (7 TR 4711.) Similarly, the AG also pointed out that the ATWACC was responsible for a higher ROE estimate and rejected it on the basis that its widespread adoption would lead to an upward cycle of ROE inflation. (6 TR 3741-3742.) ABATE also rejects the ATWACC adjustment on the basis that it “is unnecessary and has previously been rejected by this Commission.” (4 TR 1208.)

#### **E. Capital Asset Pricing Model (CAPM)**

Staff provided two CAPM analyses, a historical analysis, and a projected analysis. (7 TR 4712-4714.) The CAPM model infers that investors are exposed to

two types of risk, diversifiable (firm specific) and non-diversifiable (market) risk. The CAPM suggests that an investor is fully invested in a portfolio of stocks and thus eliminates, or greatly reduces, firm specific risk and is only exposed to market risk. The risk of an asset and thus the investor's required return is a function of the risk of that asset compared to the market. This market risk is characterized by the beta coefficient. Therefore, to estimate a cost of equity using the CAPM, one needs a risk-free rate, an estimate of beta for the proxy group, and a market return for a wide portfolio of assets. Staff used a long-term U.S. Treasury bond yield forecast for its risk-free rate, the proxy group betas from Value Line, and a market return from a wide variety of assets from 1926-2022. (7 TR 4712-4713.) Staff's historical CAPM analysis produced a ROE estimate of 10.34%. (7 TR 4713.) Staff also performed a projected CAPM analysis using Value Line market data. The projected CAPM analysis produced a ROE estimate of 13.63%. (7 TR 4715.) However, Staff goes on to explain that due to the disconnect between the outputs of the CAPM analysis versus other analyses done by Staff, the CAPM models have not been heavily relied on in the instant case for determining a fair and reasonable ROE. (7 TR 4715-4716) The AG and ABATE also performed CAPM analyses. The AG's model resulted in a 10.01% ROE output. (6 TR 3745.) ABATE summarized their CAPM results to a point ROE estimate of 9.50%. (4 TR 1204.) DTE also presented CAPM analyses with outputs ranging from 8.9% to 11.5%. (5 TR 2988.)

Staff's testimony also addressed the Company's CAPM analyses and corresponding ROE estimates. Staff disagreed with the Company's use of the

ECAPM and Hamada adjustments. (7 TR 4716.) Though Staff's testimony does not go into detail about the ECAPM, it does address the Hamadas adjustment. Staff rejects the Hamada adjustment for similar reasons to the ATWACC and displays that the Company's CAPM results would range from 8.50%-10.80% were it not for the adjustment, also removing the Empirical adjustment of the ECAPM would result in a high-end estimate of just 10.64%. (7 TR 4717.) Similarly, both the AG and ABATE also disagreed with the Company's use of the ECAPM and Hamada. (6 TR 3746-3748; 4 TR 1216-1218.)

#### **F. Risk Premium**

The risk premium approach examines the spread between historical electric utility realized stock returns and historical composite utility bond yields and develops a cost of equity estimate by incorporating the historical data with current utility-bond data. Staff used a return period of 1931 through 2022 to obtain its historical market risk premium. Staff used average yields for A-rated and BBB-rated bonds from Value Line as well as a projected Treasury bond yield. (7 TR 4718.) The risk premium model produced historical ROE estimates of 9.83% for A-rated bonds and 10.10% for BBB-rated bonds; additionally, the treasury-based method resulted in a ROE estimate of 8.77%. (7 TR 4719.)

The AG, ABATE, and DTE also provide Risk Premium analyses. The AG's Risk Premium model yields a result of 9.96%. (6 TR 3749.) ABATE concludes from its Risk Premium analyses, a result of 9.90%. (4 TR 1194.) DTE uses a regression-based Risk Premium model that outputs a result of 10.4%. (5 TR 2994.)

### **G. Other State Commission ROE Decisions**

Staff reviewed the authorized rate of return decisions rendered by other state commissions from 2021 and 2022. The average authorized ROE from those decisions was 9.38% for 2021 and 9.54% for 2022. (7 TR 4720.) The ROE data was provided by the Regulatory Research Associates, which is a unit of S&P Global Market Intelligence.

### **H. Response to Dr. Villadsen's rebuttal critique**

In rebuttal Dr. Villadsen, on behalf of DTE, criticizes Staff's analyses. The primary criticism of Dr. Villadsen was Staff's decision to assign little weight to its CAPM results. (5 TR 3052.) As explained in Staff's testimony and previously in their brief, the CAPM results Staff found were substantially different from the results of other models. (7 TR 4715-4716.) Firstly, Dr. Villadsen uses this exact logic to reject her Multi-stage DCF result, which was in her words "out of line with other results." (5 TR 2992.) Secondly, Staff chose to present the results from all its analyses, including the CAPM, and according to Dr. Villadsen, Staff increased its recommended ROE relative to case U-20836 only "slightly" less than the increase in corresponding approved ROE trends. (5 TR 3047.) Dr. Villadsen insisted the discounting of the CAPM results led to a downward bias in Staff's analysis, stating Staff's ROE results should be closer to 10.4% if all models are given equal weight. (5 TR 3052.) Staff asserts the increase in ROE recommendation since U-20836 makes the case Staff was reasonable in its discounting of its CAPM results; as not discounting the results would have caused Staff's ROE recommendation to be

largely driven by a single model's outlier result and lead to outsized ROE recommendation increases for DTE compared to the average approved ROE trends. Additionally, Staff does not historically give equal weight to all models as Dr. Villadsen suggested and in fact has routinely given little weight to the Risk Premium analysis in low interest rate environments when its outputs were significantly lower than other ROE models and would have led to lower ROE recommendations if all models were weighted equally. For these reasons, and the reasons above, the Commission should approve Staff's recommended 9.8% ROE and 5.52% overall cost of capital.

## **V. Net Operating Income**

Reduced to its essence, Adjusted Net Operating Income (NOI) is the difference between a company's operating revenues and operating expenses for the projected test year. *In re Detroit Edison's 2010–2011 Rate Case*, MPSC Case No. U-16472, 10/20/2011 Order, p 41.

### **A. Staff recommends an adjusted net operating income of \$959,795,000.**

In its initial filing, the Company recommends an adjusted net operating income (NOI) of \$836,780,000, while Staff recommends an adjusted NOI of \$959,795,000, which is \$123,015,000 greater than the company's projection.

(Appendix C, Col r, Line 1 and 41.)

Staff initially filed a projected net operating income of \$952,529,000, an increase of \$115,749,000 from the Company's originally filed net operating income

of \$836,780,000 found on Exhibit A-13, Schedule C1, Line 17. (7 TR 4589.) In this brief, Staff has updated its case and now projects a net operating income of \$959,795,000. (Appendix C, Ln 41.) A reconciliation of the updates Staff has made in this brief can be found on Appendix F, Lines 11-35.

Differences between the Staff's and the Company's total adjusted NOI are due to Staff adjustments to various Company revenue and expense projections as detailed below.

**1. Staff recommends total operating revenues of \$5,113,378,000.**

DTE projects that its total operating revenues will be \$5,112,874,000 in the projected test year, which is \$504,000 less than Staff's projection of \$5,113,378,000. (Appendix C, Col e, Line 1, 40 and 41.) Staff made adjustments to sales revenue as detailed below.

**a. Staff recommends sales revenue of \$3,640,512,000**

Staff recommends a total increase to the Company's electric sales revenue of \$504,000. (Appendix C, Col. b, Line 40.) This is composed of two adjustments, described below.

Before addressing the two adjustments, it is important to note that Staff recommends the Commission adopt the Company's forecasted electric deliveries of 44,310 Gigawatt Hours (GWh). Staff witness, Paul Ausum, provided testimony confirming Staff's review of the Company's sales forecast. (7 TR 4339). Staff did not recommend any changes to the Company's forecast, and no other party to the

case sponsored an alternative to the Company's projection. In the absence of any other deliveries forecast, Staff recommends that the ALJ and the Commission adopt the Company's projection of 44,310 GWh for the twelve months ending November 30, 2024.

With the appropriate deliveries forecast established, the adjustments recommended by Staff consist of the following.

First, Staff proposes a \$2,404,000 increase to RIA Revenue. (Appendix C, Line 3.)

Staff proposes to rely on the average number of actual RIA credits disbursed from 2019 through 2021 of 46,428 monthly credits worth \$8.50 each. (7 TR 4471.) The Company projects 70,000 monthly RIA credits. (5 TR 2094.) The Company failed to report RIA credit enrollments consistently between the filing requirements in the instant case, the Company's most recent general rate case, and its report in MPSC Case No. U-20757. The Company purports that RIA enrollment presented in testimony represents a "snapshot" in time of customers receiving the RIA credit, whereas the numbers reported in filing requirements should represent total annual credit disbursements. (7 TR 4468-4470.) Because the Company could not provide reliable and consistent reports of its RIA enrollment it is not appropriate to assume that RIA disbursements in the test year will match with the Company's 2022 figure. *Id.* It is possible that in the Company's next rate case that the reported RIA enrollment for 2022 could differ from that reported in the instant case. An average of historic RIA expense is appropriate because it includes any trend in enrollment.

Staff argues that the number of credits disbursed as reported in the filing requirements is the most appropriate data on which to base the test year projection. (7 TR 4469.) For these reasons Staff recommends the Commission and ALJ reject the Company's RIA customer count projection and approve Staff's projection based on actual, historic data which results in an increase in revenue of \$2,404,000.

Second, Staff proposes a \$1,900,00 decrease to shared asset revenue.

(Appendix C, Line 4.)

If the ALJ and the Commission accept Staff's recommended disallowances for IT projects that are shared assets, the ALJ and the Commission should also reduce the shared asset revenue.

In rebuttal testimony, Company Witness Uzenski states that the Company forecasted \$60.1M of revenue from building and IT shared assets. The capital expenses for shared assets are reflected in the rate base for DTE Electric. (Uzenski 5 TR 1570, Lines 3-7.) For their use of the assets, DTE Gas Company and other DTE entities pay DTE Electric a revenue for their allocated percentage of the shared asset IT projects in the form of a reduction in the revenue requirement. The forecasted \$60.1M includes all shared asset IT projects. If a disallowance is made to a shared IT project, the revenue from DTE Gas Company and the other DTE affiliates must also be removed. (Uzenski 5 TR 1570, Lines 15-17.) Staff agrees with this argument. If the ALJ and the Commission approve the recommended disallowances made by Staff, they should also reduce the shared asset revenue by \$1.9M.

**b. Staff recommends base fuel and purchase power revenue of \$1,361,901,000.**

The Company projected that it would receive \$1,361,901,000 in base fuel and purchase power revenue, which is equal to Staff's projection. (Appendix C, Col. c, Ln 1, 41.) Staff recommends the ALJ and the Commission adopt DTE's projection.

**c. Staff recommends other revenue and R2 of \$110,965,000.**

Staff recommends that the ALJ and the Commission adopt the Company's projection of \$110,965,000 in other revenue and R2. (Appendix C, Col. d, Line 1, 41.)

**2. Staff recommends total operating expenses of \$4,204,718,000 for the projected test year.**

Staff's recommended total operating expenses of \$4,204,718,000 is \$111,431,000 less than the Company's projection of \$4,316,149,000. (Appendix C, Col n, Line 1, 40 and 41.) Staff breaks down this \$111.431 million difference, by category, and explains the difference below:

Other O&M	\$ (128,802,000)
Depreciation & Amortization	(22,689,000)
State & Local Income Tax	9,603,000
Federal Income Tax	<u>30,456,000</u>
<b>Total Difference in Operating Expense</b>	<b>\$ 111,431,000</b>

**a. Staff recommends fuel and purchase power expense of \$1,361,901,000.**

Staff recommends fuel and purchase power expense of \$1,361,901,000, which is equal to the Company's initially filed projection. (Appendix C, Line 41.)

**b. Staff recommends Other O&M expense of \$1,173,553,000.**

Staff's initially filed projected operations and maintenance expense is \$1,169,561,000, a decrease of \$132,794,000 for the Company's originally filed projected operations and maintenance expense of \$1,302,355,000 found on Exhibit A-13, Schedule C5, Line 12. In this brief, Staff has updated its case and now projects an operations and maintenance expense of \$1,173,553,000. (Appendix C, Col g, Line 41.) A reconciliation of the updates Staff has made in this brief can be found on Appendix F, Lines 18-29.

Staff recommends Other O&M expense of \$1,173,553,000, which is \$128,802,000 less than the Company initially filed projection of \$1,302,355,000. (Appendix C, Col g, Line 1, 40 and 41.) Staff proposes the following adjustments to Other O&M Expense:

i.	STEAM POWER GENERATION	
	1. Reduce Periodic Outage Adjustment	\$(8,947,000)
	2. Trenton Channel Closing	2,224,000
ii.	UNCOLLECTIBLES	
	Uncollectible Expense	(11,805,000)
iii.	REGULATED MARKETING	

	EV Emerging Technology Fund	(1,000,000)
iv.	<b>CORPORATE SUPPORT</b>	
	1. Incentive Compensation	(43,821,000)
	2. Restricted Stock	(6,534,000)
	3. Membership Fees	(20,000)
	4. Low Carbon Resources Initiative	(601,000)
	5. Oracle Forecasting Tool	(6,000)
	6. Infrastructure Automation Maturity	(34,000)
	7. Infrastructure Operations Center (IOC)	(34,000)
	8. Changing Bill Size	(2,000)
	9. Customer Service Sales & Service	(330,000)
	10. Pre-Pay II	(344,000)
	11. Level 2 Cost Estimate Disallowance- 20%	(3,151,000)
	12. Unsupported O&M	(44,043,000)
v.	<b>PENSION AND BENEFITS</b>	
	1. New Hire Retiree VEBA	(2,604,000)
	2. Employee Savings Plan	(5,049,000)
	3. Active Healthcare	<u>(2,699,000)</u>
	<b>Total difference in O&amp;M Expense</b>	<b>\$(128,802,000)</b>

**i. Staff recommends reducing steam power generation O&M expense by \$6,723,000.**

Staff recommends reducing steam power generation O&M expense by \$6,723,000. (Appendix C, Col g, Line 7-8.) This is composed of two adjustments described below.

First, Staff recommends a \$8,947,000 reduction to reduce periodic outage O&M expense. (Appendix C, Line 7.) Second, Staff recommends a \$2,224,000 increase to Trenton Channel closing O&M expense. (Appendix C, Line 8.)

Staff witness Kindschy testifies that DTE Electric's periodic outage O&M expenses for its north area plants should be reduced. (7 TR 4516-4517.) The Company made an increase to its projected test year O&M expenses of \$11,547,000 due to reduced outages at its Belle River and Greenwood plants during the 2021 historical year. (5 TR 2370-71; Exhibit A13 C5.1 Revised.) DTE Electric calculated this additional O&M for the projected test year by taking the average of its historic periodic outage spending from 2017-2020 for its Belle River and Greenwood plants, and then applied inflation. (7 TR 4516; Exhibit S-21.5.)

After reviewing the periodic outage spending for all three of the Company's remaining steam generation plants, Staff witness Kindschy determined that DTE Electric spent less than average in 2021 at its Belle River and Greenwood plants but spent more than average at its Monroe plant. (7 TR 4516.) From this, witness Kindschy concluded that the periodic outage adjustment should have included all three of the Company's remaining steam generating plants. When she included the Monroe plant into the 2017 to 2020 average, the periodic outage spending adjustment was reduced to \$2,599,978 after inflation. (7 TR 4516; Exhibit S-21.6 p 6.) The difference between Staff's periodic outage spending adjustment and DTE Electric's is a reduction to steam power generation O&M expense of \$8,946,862. (7 TR 4517; Exhibit S-21.6; p 6.)

In rebuttal testimony, Company witness, Justin L. Morren, argues that Staff erred by including the spending for the Monroe plant into the periodic outage average, and in particular the spending in 2020 where he states the Monroe plant did not have a major periodic outage due to the COVID-19 pandemic. (5 TR 2425.) First, Staff used the same years that DTE Electric used to determine the periodic outage adjustment for its north area plants. (7 TR 4515-4516; 5 TR 2424-2425.) If it was not appropriate to use periodic outage spending for Monroe in 2020, then it should also have not been appropriate to use 2020 spending for the north area plants as those plants experienced the same atypical year.

Second, Staff considered the use of various averages that included actual data for 2021 and 2022, as well as an average without 2020, before deciding to use the same years of 2017-2020 that DTE Electric used for its periodic spending adjustment. Referring to Exhibit S-21.6 page 6, the simple average of the Total for the Monroe, Belle River, and Greenwood plants for 2017-2021 is \$21,300,192, for 2017-2022 is \$21,162,132, and for 2017-2022 excluding 2020 is \$21,833,368. Since all of these averages are relatively close to the average for 2017 to 2020 of \$21,773,952 that Staff ultimately used, DTE Electric's total periodic outage spending O&M for its three steam generating plants remains relatively constant regardless of the historical years chosen. Furthermore, the Company's argument that Staff erred by including periodic outage spending for Monroe in 2020 with the COVID-19 pandemic holds no weight. The 2017-2022 average excluding 2020 was \$21,833,368, which is very close to the 2017-2020 average that Staff used in its

calculation of \$21,773,952. Therefore, the inclusion of Monroe periodic outage spending for 2020 does not materially change the calculation or Staff's resulting adjustment. For these reasons, Staff recommends that DTE Electric's periodic outage O&M expense be reduced by \$8,947,000.

Staff also recommends a \$2,224,000 increase to generation O&M expense for the amount the Company removed for the closing of the Trenton Channel Power Plant. (Appendix C, Line 8.) Through discovery, Staff witness Kindschy learned that DTE Electric applied inflation twice to the O&M for Trenton Channel, thereby removing too much O&M in the test period for the retirement of the plant. Staff determined it was reasonable to make a correction for the amount that the DTE Electric inadvertently removed for Trenton Channel and recommends that the Commission increase the Company's O&M expense by \$2,224,000. (7 TR 4517; Exhibit S-21.7.) Staff notes that this adjustment was prepared from the Company's originally filed exhibit while the revised Exhibit A-13 Schedule C5.1 submitted later in this case has been amended for this error and now shows the correct amount for the Trenton Channel Power Plant closing under note 6 of \$22,175,000.

**ii. Staff recommends reducing uncollectible expense by \$11,805,000.**

Staff recommends reducing uncollectible expense by \$11,805,000. (Appendix C, Line 11.)

Staff, through its witness, Shannon Rueckert, recommends an electric uncollectible expense (UCX) projection of \$42,809,000 which is \$11,805,000 less

than the Company's projection of \$54,614,000. In direct testimony Staff supported an UCX projection of \$41,960,000 calculated from the direct write-off method applied to present revenue. The Company rebutted Staff's exclusion of non-energy write-offs from its calculation, insisting that the Company must be allowed to recover these expenses in rates. (5 TR 2105.) Staff requested the cause of non-energy write-offs from the Company. After review Staff does not contest the inclusion of non-energy write-offs in the UCX calculation which were found to be written off damage claims. The Company used a three-year average of accrual based uncollectible expense for 2019-2021, resulting in \$54.6 million of uncollectible expense. (7 TR 4675.) Staff asserts that the Company's projection is unreasonable for several reasons. Staff used the most current years expenses available in their projection, 2020 through 2022. Also, the Company does not consider electric revenues as a factor for projecting uncollectible accounts expense. Staff recommends the direct write-off method for projecting UCX arguing that actual write offs, less recoveries applied to electric service revenue is more accurate for uncollectible accounts expense projections for rate making purposes. Using the cash basis, direct write-off method, uncollectible accounts are written off directly to expense as they become uncollectible. The direct write-off method is also used for U.S. income tax purposes. Witness Rueckert argued that the Company's accrual-based average should not be used because it can include accruals for "special circumstances" that are speculative because they are "expected" to be charged off. He asserted that these should not be included in historical averages used to forecast future UCX until they

are realized. (7 TR 4676.) In rebuttal, Company witness, Griffie, argued that historical write-offs should be applied to proposed revenue. (5 TR 2105.) Staff witness Rueckert recommends the direct write-off method be applied to total present revenue presented on exhibit: S-6, schedule F2, ln 49, col (b), supported by Staff witness, Isakson. Staff witness, Rueckert, asserted that use of proposed revenue as the Company suggests creates an iterative calculation,” and that Staff’s methodology “applied to total present revenue encourages the Company to continually improve efforts to reduce UCX below the amount set in rates.” (7 TR 4676.) Witness Rueckert cited exhibit S-8.1, column (k) as evidence showing that the amount set in rates is consistently above what the Company has realized in net write-offs. (7 TR 4677.) This method has been approved by the Commission in MPSC cases No. U-20322, September 26, 2019, Order, p 102 and MPSC cases No. U-18124, July 31, 2017, Order, p 89-90. Therefore, Staff recommends the ALJ and Commission approve an Uncollectible Expense projection of \$42,809,000, which is \$11,805,000 less than the Company’s projection of \$54,614,000.

**iii. Staff recommends reducing regulated marketing O&M expense by \$1,000,000.**

Staff recommends reducing regulated marketing O&M expense by \$1,000,000 for EV emerging technology fund. (Appendix C, Line 14.)

While Staff supports the idea behind the Emergency Technology Fund, it is uncomfortable with it becoming permanent or receiving additional funding until the

program matures. Staff witness Freeman stated this in his testimony. (Freeman, 7 TR 4429.)

**iv. Staff recommends reducing corporate support O&M expense by a total of \$98,922,000.**

Staff recommends reducing corporate support O&M expense by \$98,922,000. (Appendix C, Line 17-28.) This is composed of twelve adjustments described below.

*Staff recommends reducing incentive compensation O&M expense by \$43,821,000. (Appendix C, Line 17.)*

In its initial filing, the Company proposed that the Commission include a \$63,903,000 incentive compensation O&M expense in the revenue requirement. (5 TR 1383; Exhibit S-9.0.) However, portions of this expense should be disallowed by the ALJ and Commission as compensation tied to the Company's financial metrics.

Staff witness, Theresa McMillan-Sepkoski, recommended disallowance is the portion of the Company's employee incentive compensation plan (EICP) expense that is tied to achieving financial metrics. (7 TR 4577.) Staff's recommended \$43,821,000 reduction is made up of two parts. The first is \$43,399,000 in O&M financial objectives that are based on the achievement of financial performance measures. (7 TR 4577.) The second is \$422,000 in Long Term Incentive Plan (LTIP) for Nuclear Generation that is paid out in performance shares.

The Company has incentive compensation programs that are, in part, based on achieving financial metrics. Staff does not dispute the overall reasonableness of employee compensation, but instead argues that there should be a distinction on

who pays based on the metrics included. For example, ratepayers benefit from operational metrics that promote reliability and safety. Stockholders benefit from financial metrics based on earnings per share and operating cash flow. The Commission has long held that shareholders, not ratepayers, must pay for incentives related to increasing profits, and no party has given a reason for the Commission to reverse that stance. (7 TR 4577-4578.)

Staff's recommendation to the ALJ and Commission is based on the Commission's Order in Case No. U-20836. In that case, the Commission disallowed employee incentive compensation tied to financial measures. *In re DTE Electric Rate Case*, MPSC Case No. U-20836, 11/18/22 Order, p 301. This is consistent with prior Commission orders finding that when incentive compensation plans are tied to Company earnings and cash flow, the plans largely benefit shareholders. (*Id.*) Applying the same reasoning to the instant case, Staff aligned the cost of financial performance measures within the incentive compensation plan to the group that benefits from those financial performance measures-shareholders.

In its rebuttal testimony, the Company argues that the recommendation above is based "exclusively on the Commission's traditional practice." (5 TR 1407.) The Company asserts that Staff's position does not take into account the reasonableness of the Company's compensation policies and practices overall. (5 TR 1411.) Indeed, Staff's position is based on long-standing Commission precedent. But that does not mean Staff's analysis ignores reasonableness. The Commission has, as explained above, examined similar incentives in previous cases and has

found that the “disallowance of compensation tied to achievement of non-financial performance objectives” is “reasonable and prudent given that incentive compensation tied to financial performance measures has not been shown to benefit ratepayers.” (*In re DTE Electric Rate Case*, MPSC Case No. U-20162, 5/2/19 Order, p 93.)

MNSC recommends the ALJ and Commission to require incentive compensation measures that focus on areas the Company needs to improve on. Reliability and residential affordability. In the absence of any improvement in reliability, this should trigger disallowances for executive compensation. (6 TR 3456-3457.)

The Attorney General (AG) recommends to the ALJ and Commission to disallow \$43,399,000 of the financial metrics portion of incentive compensation and only approve 52%, or \$10,142,000 of the incentive compensation tied to operational metrics based on an overall percentage of achievement of the non-financial measures by the Company. (6 TR 3790-3791). The AG also recommends the removal of the forecasted \$5.6 million deferred regulatory asset balance from working capital since the level of performance of achieving the operating measures is unknown till after the order for this case by the Commission is filed. (6 TR 3765.)

Souladarity recommends to the ALJ and Commission reject the Company’s request for \$62.9 million for incentive compensation, and an additional amount of \$11.7 million incentive compensation that is paid to DTE Energy’s top 5 executives.

These executives should be required to share the economic burden of incentive compensation. (6 TR 3987-3988.)

ABATE recommends to the ALJ and Commission to reject \$43.9 million of incentive compensation, consistent with the Commission's prior case findings. (4 TR 1117-1119.)

Staff's recommendation to the ALJ and Commission also includes disallowing the LTIP incentive payout for the Nuclear Generation in the amount of \$422,000. This LTIP payout is through performance shares. Although the Nuclear Generation incentive compensation is 20% based on total shareholder return and 80% based on operating measures, Staff has disallowed the total payout because the value of the performance shares depends on the financial operation of the Company. (5 TR 1410; Exhibit S-9.0.) This payout is different from a cash incentive payout and can be influenced by the financial performance of the Company.

*Staff recommends reducing restricted stock O&M expense by \$6,534,000.*

Staff witness Theresa McMillan-Sepkoski recommends disallowing the Restricted Stock amount of \$6,534,000 that the Company paid out to employees for assisting the Company in reaching its financial performance goals be removed from the revenue requirement. (Appendix C, Line 18; Exhibit S-9.2, pp 2-3.) The value of the awards granted is dependent on the DTE Energy Company stock price. According to Company witness Cooper, "the expense is recognized based on the value of DTE Energy's stock price at the date of grant..." (5 TR 1413.) However,

the booklet provided as Exhibit S-9.2 further explains that these awards “enable [recipients] to share in the value created for shareholders, reward [recipients] for sustaining the Company’s profitable growth, and link [recipients] rewards to long-term financial results. (Exhibit S-9.2, emphasis added.)

As the Company’s Restricted Stock awards are tied to value created for shareholders, sustaining profitable growth, and rewarding financial results, excluding this expense would be consistent with the Commission’s long-standing position of disallowing compensation expenses related to financial metrics.

The Company argued in rebuttal testimony that the Restricted Stock is not based on financial performance of the Company. (5 TR 1413.) However, as stated in Staff’s testimony, the Company pays this out under the LTIP even though it does not consider the Restricted Stock LTIP. As has been established in previous cases, for example MPSC Case No. U-20561, Order 5/8/20, pp 202-203 and MPSC Case No. U-20836, Order 11/18/22, p 303, the ALJ and Commission have disallowed any portion of compensation, including Restricted Stock payouts related to the achievement of financial measures be included in the revenue requirement.

For all reasons presented above, Staff urges the ALJ and Commission to remove \$6,534,000 from the Company’s proposed O&M expense. Excluding these expenses is reasonable and consistent with Commission precedent.

*Staff recommends reducing membership fees O&M expense by \$20,000.*

Staff witness, Theresa McMillan-Sepkoski, recommends to the ALJ and Commission reducing membership fees O&M expense by \$20,326 that the Company stated in Exhibit S-9.3 and Exhibit S-9.4 was inadvertently not removed from the revenue requirement. (Appendix C, Line19.) The Company did not object in rebuttal testimony.

*Staff recommends reducing low carbon resources initiative O&M expense by \$601,000.*

Staff witness, Theresa McMillan-Sepkoski, recommends to the ALJ and Commission to reduce O&M expense by \$601,470 for miscellaneous general expense-LCRI membership for research and development (R&D) costs. (Appendix C, Line 20.)

The Company proposed to recover the fee for membership in the Electric Power Research Institute (EPRI) and the Gas Technology Institute (GTI). (5 TR 2369; 5 TR 2428.) The Company claims the initiative could aid the Company's corporate decarbonization goal. However, the Company failed to provide an explanation of the direct benefit/impact of this membership is to its customers. Staff requested the Company to describe in detail how this membership cost is a benefit to ratepayers, but the Company referred back to witness Morren's testimony which only spoke to Company corporate goals. (7 TR 4581; Exhibit S-9.6.)

The ALJ has recommended disallowing R&D costs and the Commission has agreed with the ALJ's findings, *In re DTE Electric Rate Case*, MPSC Case No. U-20940, 12/9/21 Order, pp 180-181. The Commission stated that the Company

should provide better support that would show the expected benefit/impact to its customers.

In rebuttal, the Company states that this membership is critical in supporting the net zero goals the Company has set to achieve for the corporation. (5 TR 2429.) This still does not satisfy the Commission's request for cost savings that would benefit the ratepayers and detail the reduced risk and resilience.

Souladarity recommends the disallowance of \$5.6 million in membership dues because the Company has failed to prove these costs are just and reasonable. (6 TR 3988-3990.)

Staff recommends to the ALJ and Commission to disallow the LCRI O&M expense for research and development costs of \$601,470.

*Staff recommends reducing Oracle forecasting tool O&M expense by \$6,000.*

The ALJ and the Commission should disallow \$6,250 in O&M for the Oracle Forecasting Tool. In direct testimony, Staff witness Danielle R. Rogers originally recommended a \$0.01M O&M disallowance, consistent with Staff's recommended capital expense disallowance in Section III.B.5.c. (Rogers 7 TR 4657, Line 7.) If the capital expenditure is not being spent, the associated O&M expense is unnecessary. (Rogers 7 TR 4662, Lines 8-11.) However, this number has been updated to \$6,250 to reflect that only 75% of the projection is attributable to DTE Electric.

Company witness Theresa M. Uzenzki disagreed with Staff's original recommendation stating that the O&M expenditures were not specifically included

in the Company's requested revenue deficiency. (Uzenski 5 TR 1567, Lines 7-8.)

The projected O&M requested by the Company is calculated using the 2021 historical expense and adding inflation. She further states:

If the specific projects proposed for disallowance are not executed, then the resources will be redeployed to other projects that were originally prioritized for a later implementation. Since the O&M included in the Company's projection adjustments was not based on specific projects, but represents the cost for an aggregate collection of projects, the Commission should reject these disallowances. [Uzenski 5 TR 1567, Lines 14-19.]

Staff disagrees with this methodology. Staff interprets this as an O&M budget. Staff is responsible for reviewing the reasonableness and prudence of IT project expenses. Reasonableness and prudence cannot be determined for a budget as a whole. There would be no way to determine if the costs are being spent on used and useful projects or used at all. It would be unfair to pass these uncertain expenses onto ratepayers. In its U-20836 order, the Commission stated,

The Commission also finds it appropriate that the Staff recommends adjustments to individual projects rather than to a budget as a whole. That is the only way to determine whether a project presents benefits to ratepayers. The Commission's determination of reasonableness and prudence (and its obligation to protect ratepayers) involves more than the simple hope that the over- and under-projections balance one another out. MCL 460.6; MCL 460.6a. *In re DTE Electric Company's 2020 rate case*, MPSC Case No. U-20836, 11/18/2022 Order, p 192.

Company witness, Theresa M. Uzenski, goes on to state that if the ALJ and Commission were to adopt Staff's O&M recommended disallowance, it should be reduced by the amount not applicable to DTE Electric. The amount of O&M attributable to DTE Electric is about 75%. For the total recommended \$5.2M associated with individual IT projects and IT projects with Level 2 cost estimates,

this would be \$3.9M. The remaining 25%, or \$1.3M, is related to DTE Gas Company and other DTE affiliates. Staff agrees with this argument and revises its recommended O&M disallowance for the Oracle Forecasting Tool and the following five IT projects, as well as IT projects with Level 2 cost estimates, be reduced by 25%. (Uzenski 5 TR 1567 Lines 24-25 and 1568 Lines 1-4)

*Staff recommends reducing infrastructure automation maturity O&M expense by \$34,000.*

The ALJ and the Commission should disallow \$34,370 in O&M for the Infrastructure Automation Maturity Project. Staff witness, Danielle R. Rogers, originally recommended a \$0.05M O&M disallowance in direct testimony, consistent with Staff's recommended capital expense disallowance in Section III.B.5.d. (Rogers 7 TR 4658, Lines 16-17.) If the capital expenditure is not being spent, the associated O&M expense is unnecessary. (Rogers 7 TR 4662, Lines 8-11.) However, this number has been updated to \$34,370 to reflect that only 75% of the projection is attributable to DTE Electric.

*Staff recommends reducing infrastructure operations center O&M expense by \$34,000.*

The ALJ and the Commission should disallow \$34,370 in O&M for the Infrastructure Operations Center Automation Project. In direct testimony, Staff witness Danielle R. Rogers originally recommended a \$0.05M O&M. This is consistent with Staff's recommended capital expense disallowance in Section III.B.5.e. (Rogers 7 TR 4658, Lines 16-17.) If the capital expenditure is not being

spent, the associated O&M expense is unnecessary. (Rogers 7 TR 4662, Lines 8-11.) However, this number has been updated to \$34,370 to reflect that only 75% of the projection is attributable to DTE Electric.

*Staff recommends reducing changing bill size  
O&M expense by \$2,000.*

Consistent with Staff's position in section III. B. 5. b. iii., the Commission should disallow \$2,000 in O&M expenses for the Changing Bill Size Project. In its direct testimony Staff originally recommended \$3,000 in O&M disallowance, however, this number has been updated to \$2,000 to reflect that only 75% of the projection is attributable to DTE Electric. For all the reasons previously discussed in this brief regarding that project, Staff recommends a full disallowance of all costs associated with that project, including O&M costs.

*Staff recommends reducing customer service sales & service  
O&M expense by \$330,000.*

Consistent with Staff's position in section III. B. 5. b. ii., the Commission should disallow \$330,000 in O&M expenses for the Customer Service Sales & Service Project. In its direct testimony Staff originally recommended \$440,000 in O&M disallowance, however, this number has been updated to \$330,000 to reflect that only 75% of the projection is attributable to DTE Electric. For all the reasons previously discussed in this brief regarding that project, Staff recommends a full disallowance of all costs associated with that project, including O&M costs.

*Staff recommends reducing Pre-Pay II  
O&M expense by \$344,000.*

Consistent with Staff's position in section III. B. 5. b. i., the Commission should disallow \$344,000 in O&M expenses for the PrePay Phase II Project. In its direct testimony Staff originally recommended \$458,333 in O&M disallowance, however, this number has been updated to \$344,000 to reflect that only 75% of the projection is attributable to DTE Electric. For all the reasons previously discussed in this brief regarding that project, Staff recommends a full disallowance of all costs associated with that project, including O&M costs.

*Staff recommends reducing Level 2 Cost Estimates  
O&M expense by \$3,151,000.*

The ALJ and the Commission should disallow \$3.15M in O&M expenses for projects with a Level 2 cost estimate. Staff witness Danielle R. Rogers originally recommended a \$4.2M O&M adjustment. (Rogers 7 TR 4662, Lines 14-19.) This number has been revised to \$3.15M to reflect that only 75% of O&M for IT projects with Level 2 cost estimates applies to DTE Electric. This recommendation is consistent with Staff's recommended capital expense disallowance in Section III.B.5.f. These projects are incomplete and indefinite in nature as they are given over a year before implementation and have not been through the comprehensive review process, final approval, or budget allocation. (Rogers 7 TR 4662, Lines 17-19.)

*Staff recommends reducing Unsupported O&M  
expense by \$44,043,000.*

Staff proposed a \$44.04M IT O&M disallowance because it was unsupported in the Company's application. (Rogers 7 TR 4663, Lines 3-4.) The Company projected a \$69.06M O&M expense (Staff Exhibit S-12.10 p 5), however it has only supported \$1.78M in 1 month of 2023 and \$19.04M in 11 months in 2024 to equal \$20.82M in the test year. (Staff Exhibit S-12.9, Line 115.) Any expenses requested by the Company for inclusion in rates should be supported with evidence in testimony and exhibits to show they are based on prudent projections. This is not the case for \$44.04M. These expenses are not connected to a project or investment. Company testimony states operating expenses include software maintenance, software licenses, cloud computing fees, software as a service, hardware and software defect remediation, business support services, and IT administration. (Uzenski 5 TR 1519 Lines 1-4.) In rebuttal testimony, Company witness, Theresa M. Uzenski, added that 50% of the projected O&M expense supports software maintenance such as vendor support for software and hardware failures, bug fixes, upgrades, and security patch installations, and 35% is for payroll for IT Staff who support daily operations. (Uzenski 5 TR 1569, Lines 10-17.) Staff maintains its position. The Company has the burden to prove their expenses are reasonable and just. While the Company added in rebuttal that 50% of the projected O&M expense is for software maintenance and 35% is for payroll, Staff has no ability to understand if these costs or percentages are appropriate. The information provided by the Company is insufficient to adequately deem these requested O&M expenses

prudent. Because the Company has not met its burden of proof, it is inappropriate to pass this \$44.04M in IT O&M costs onto ratepayers.

Based on the above discussions on individual IT project O&M, O&M for projects with Level 2 cost estimates, and unsupported IT O&M, the ALJ and the Commission should disallow a total of \$47.95M in requested IT O&M expenses.

**c. Staff recommends reducing pension and benefits O&M expense by \$10,352,000.**

Staff recommends reducing pension and benefits O&M expense by \$10,352,000. (Appendix C, Line 31-33.) This is composed of three adjustments described below.

*Staff recommends reducing new hire VEBA O&M expense by \$2,604,000.*

Staff recommends reducing new hire VEBA O&M expense by \$2,604,000. (Appendix C, Line 31). The Staff, through its witness, Shannon Rueckert, recommends a new hire VEBA Expense projection of \$11,363,000 which is \$2,604,000 less than the Company's projection of \$13,967,000. Company witness, Cooper, projected a VEBA expense with annual escalations of 25% purportedly based on the Company's recent experience. (5 TR 1357.) Witness Rueckert noted that the Company did not support its 25% escalation rate in its exhibits. (7 TR 4677.) Staff requested the Company's calculation of the rate, and its response is presented in Exhibit S-8.3. Columns (m.) through (n.) show 5 and 4-year averages of the Company's recent experience, respectively. In rebuttal testimony, Company

witness Cooper stated that Staff Witness, Rueckert, relied upon the annual increase in the Company's new hire VEBA expense, which is impacted by changes in cost capitalization. (5 TR 1421.) Staff exhibit S-8.3 shows that the Company's capitalization rate consistently increased from 2019-2021 which in turn lowers the amount expensed proportionately. Company witness Cooper confirmed the increased capitalization rates in rebuttal stating that, "increase[s] in the proportion capitalized is a result of the Company's significant increase in its capital expenditures program over the last five years." (5 TR 1422.) This, in turn, lowers the amount of VEBA costs expensed. Staff witness, Rueckert's, method of projection considers annual increases in capitalization rates by utilizing a 5-year average annual growth rate (AAGR) of the expensed portion of VEBA. In rebuttal, witness Copper noted the significantly lower annual average growth in the expensed portion of VEBA costs, at 16.5%, in contrast to the total VEBA costs annual average growth of 20.1%. (5 TR 1422.) The Company selectively excluded year 2020 from its 4-year average increase calculation citing its own assumptions and realizations that costs were less than expected. (7 TR 4678.) Staff witness Rueckert contested the Company's selective exclusion from the averaging growth rate based on its own unrealized assumptions. He stated, "that while Company assumptions are its best efforts, they will not always be reflective of what it realizes. And that it is necessary to include the actual changes in expense from year to year when methods like average annual growth rates (AAGR) are used." (7 TR 4678.) Therefore, Staff recommends the ALJ and Commission approve a VEBA expense projection of

\$11,363,000, which is \$2,604,000 less than the Company's request of \$13,967,000 based on an AAGR of 16.5%, reflective of the five-year average including 2020.

*Staff recommends reducing employee savings plan  
O&M expense by \$5,049,000.*

Staff recommends reducing employee savings plan O&M expense by \$5,049,000.

(Appendix C, Line 32). The Staff, through its witness, Shannon Rueckert, recommends an employee savings plan expense (ESP) projection of \$31,356,303 which is \$5,049,115 less than the Company's projection of \$36,405,418. In direct testimony, witness Rueckert acknowledged an error in his projection which produced a projection of \$32,256,619. This error was corrected on Exhibit S-8.4.

The corrected projection is \$31,356,303. Company witness Cooper used an annual increase rate of 8.0% and applied it to the historic test year expense. (7 TR 4679.)

This resulted in a projected test year expense of \$36,405,418. The Company selectively omitted year 2021 from the average growth calculation of its annual increase rate. Company witness Cooper stated that the "lower than typical increase in Employee Savings Plan expense in 2021 . . . was a non-recurring item that should be eliminated from the historical average . . . ." However, the Company also noted that "the low increase in Employee Savings Plan expense continued into 2022."

(7 TR 4679). Staff witness Rueckert used a 5-year average annual growth rate based on the Company's historic expensed portion of ESP costs from consecutive years 2018-2022 to calculate an average annual growth rate of 2.9%. In rebuttal, witness Cooper exclaimed that Staff's method is flawed because it includes the

impact of changes to cost capitalization. And that “if the Company’s proportion of Employee Savings Plan costs capitalized had remained unchanged from the level in 2016 at 30.7%, the Company’s Employee Savings Plan expense would have been \$4.446 million higher in 2022 . . . .” (5 TR 1427). However, the Company’s capitalization rate did not remain unchanged. In fact, capitalization rates increased annually from 2019-2022 as shown on Exhibit S-8.4, line 12 which reduced the proportion of the total amount expensed. Therefore, Staff recommends the ALJ and Commission approve an ESP expense projection of \$31,356,303 which is \$5,049,115 less than the Company’s request of \$36,405,418.

*Staff recommends reducing active healthcare  
O&M expense by \$2,699,000.*

Staff recommends reducing active healthcare O&M expense by \$2,699,000. (Appendix C, Line 33). The Staff, through its witness, Shannon Rueckert, recommends an active healthcare expense projection of \$61,854,000 which is \$2,699,000 less than the Company’s projection of \$64,553,000. In direct testimony Staff supported a projected active healthcare expense of \$59,111,000. This projection was based on the Company’s adjusted historic test year. Through discovery, the Company asked Staff to confirm if use of the Company’s historic test year implied support for witness Copper’s constant dollar adjustment. While Staff did not contest the Company’s choice to reduce its historic test year basis, it does not support its constant dollar adjustment in principle. (5 TR 1430). In lieu of endorsing the Company’s constant dollar adjustment, Staff changed its projection to

utilize the unadjusted historic test year amount projected forward with an average annual growth rate of 2.31% calculating a forecast expense of \$61,854,000. The Company utilized annual increase trend factors provided by the actuary Willis Tower Watson (WTW) of 6.00% in 2022, 5.50% in 2023, and 5.00% in 2024 to project its active healthcare expense from an adjusted historic test year amount. (7 TR 4682). The historic test year amount was reduced by the Company's Constant Dollar adjustment. Company witness Cooper testified that its active healthcare expense is volatile. However, the annual increases in trend factors provided by WTW and used by the Company are not reflective of the expense's volatility. Witness Rueckert cited the fact that the Company has not experienced annual growth in active healthcare near the rates that WTW predicts. The Company's average annual growth rate for the expensed portion of active healthcare costs is 2.31%. (7 TR 4682.) In rebuttal, Company witness Cooper purported that Staff's method conflates changes in the Company's active healthcare costs with changes in the proportion of those costs that are expensed. (5 TR 1430.) Company Exhibit A-37 BB6, line 12, shows that the percentage expensed for active healthcare costs has consistently decreased from 2016-2021. This decreases proportionately reduced the amount of costs expensed annually from the amount of costs capitalized. Staff asserts that the changes in the percentage of costs expensed are captured in its projection by averaging the amounts expensed. Changes in capitalization rates are reflected in Staff's average annual growth rate of the expensed portion. Company witness Cooper exclaimed that Staff Witness, Rueckert, did not adjust the active

healthcare expense in 2018 included in his average for the impact of a one-time refund from Blue Cross Blue Shield of Michigan, that the Commission required the Company to amortize back to customers in its Order in Case No. U-20162. (5 TR 1430.) It is Staff's position that the impact of the one-time refund be included in the average annual growth rate as the refund was ordered amortized back to customers. This provides an accurate reflection of the expense the Company incurred for 2018. Therefore, Staff recommends the ALJ and Commission approve an active healthcare expense projection of \$61,854,000 which is \$2,699,000 less than the Company's projection of \$64,553,000.

**d. Staff recommends depreciation and amortization expense of \$1,146,233,000.**

In its initial filing, DTE projected that its depreciation and amortization expense would be \$1,168,921,000. Staff's depreciation expense of \$1,146,233,000 is \$22,689,000 less than the company's projection. (Appendix C, Col h, Line 1, 40 and 41.) Staff's depreciation and amortization expense is less than the Company's because of the impact of Staff's capital expenditure disallowances on depreciation expense. See Section III.B for Staff's capital expenditure disallowances. Additionally, in DTE's rebuttal the Company recommend if the Commission accepted Staff's proposed disallowances listed on Company witness Uzenski's Rebuttal Exhibit A-36, Schedule AA2, there should not be any reduction to depreciation expense for those items. (5 TR 1572.) Staff's brief corrected its depreciation reductions for those items except for the portion projected to be in-

service in the test year. The Company agreed in discovery response STDE-20.2 that it is reasonable to remove depreciation expense on the portion included in plant in service. (Exhibit S-24.) This results in Staff recommended depreciation and amortization expense of \$1,146,233,000.

**~~e.~~ e. Staff recommends property tax expense of \$320,250,000.**

Staff recommends the ALJ and the Commission adopt the company's projected property tax expense of \$320,250,000. (Appendix C, Col I, Line 1.)

**~~d.~~ f. Staff recommends other tax expense of \$50,173,000.**

Staff recommends the ALJ and the Commission adopt the company's projected other tax expense of \$50,173,000. (Appendix C, Col j, Line 1.)

**~~e.~~ g. Staff recommends state and local income tax expense of \$74,106,000.**

Staff recommends state and local income tax expense of \$74,106,000, which is \$9,603,000 greater than the company's projection of \$64,503,000. (Appendix C, Col k, Line 1, 40 and 41.) Staff's state and local income tax is different than the company's due to Staff's adjustments to the Company's projected revenues and expenses.

**~~f.~~ h. Staff recommends federal income tax expense of \$77,225,000.**

Staff recommends federal income tax (FIT) expense of \$77,225,000, which is \$30,456,000 greater than the company's projection of \$46,769,000. (Appendix C, Col

l, Line 1, 40 and 41.) Staff's adjustments to the Company's projected revenues and expenses are responsible for the difference.

**~~g.~~ i. Staff recommends other utility (income)/deductions of \$1,277,000.**

Staff recommends the ALJ and the Commission adopt the company's projected other utility (income)/deductions of \$1,277,000. (Appendix C, Col m, Line 1.)

**~~h.~~ j. Staff recommends a total allowance for funds used during construction (AFUDC) operating income of \$54,114,000.**

Staff recommends AFUDC of \$54,114,000, which is \$11,079,000 greater than the Company's original projection of \$43,035,000. (Appendix C, Col p, Line 1, 40, 41.) Staff's increase offsets the Fermi Main Unit Generator project being included in CWIP rather than plant in service (PIS) in this brief due to the Company confirming it is no longer scheduled to go into service in the test year through its discovery response STDE-21.1. (Exhibit S-25.) Additionally, Staff recommends that any capital expenditure adjustment adopted by the ALJ or the Commission which was projected not to be in-service during the test year shall not have any adjustment to CWIP and corresponding AFUDC which is contrary to DTE's rebuttal testimony. (5 TR 1572-1573.) After DTE's rebuttal, the Company, confirmed in its discovery response to Staff STDE-20.1a, agreed that the impact to revenue deficiency is the same if: (1) removing disallowed CWIP from rate base and the corresponding AFUDC credit; (2) leave the disallowed CWIP in rate base and the corresponding AFUDC credit in operating income. Also, part b of the discovery

response STDE-20.1b. the Company agreed it is amenable to the proposed methodology of outlining the individual disallowances but leaving both the CWIP and related AFUDC in the exhibits and schedules. Therefore, Staff recommends if the ALJ and Commission adopt any of the parties' adjustments that were projected in CWIP that it outlines the individual disallowance but leave both CWIP and related AFUDC in the exhibits and schedules as it is unnecessary to make any corresponding reductions to CWIP and AFUDC because those changes are onerous would have zero impact on the revenue deficiency.

**i.k. Staff recommends loss on reacquired securities of \$2,980,000.**

The Company projected Other Operating Income reduction of \$2,980,000 for loss on reacquired securities. Staff recommends the ALJ and Commission adopt the Company's projection. (Appendix C, Col q, Line 1.)

**j.l. Staff recommends tree trim surge program revenue deficiency of \$8,847,000.**

The Company projected tree trim surge program revenue deficiency of \$8,847,000. (Appendix A, Line 9; Appendix A.1, Line 4.) Staff recommends the ALJ and the Commission approve \$8,847,000 for the tree trim surge program revenue deficiency. (7 TR 4589.)

## VI. Cost of Service and Rate Design

### A. **The Commission should approve Staff's proposal to use the Class Peak method to allocate demand-related distribution plant costs for the secondary voltage level.**

Staff has proposed in this case to allocate demand-related distribution plant costs for the secondary voltage level using allocator 205. Allocator 205 will allocate these costs to the applicable secondary classes based on each class's forecasted non-coincident peak demands. This is also referred to as the Class Peak method. (7 TR 4602.) The Company currently allocates demand related distribution plant costs for the secondary voltage level using allocator 300, which is based upon the forecasted sum of the individual customer maximum demands (SIMD). (5 TR 3170.) The SIMD sums the individual non-coincident peak maximum demand of each customer contributing to the costs of secondary equipment. Because the vast majority of secondary equipment is not dedicated to individual customers but shared among multiple customers, it is less appropriate to rely on SIMD than using a measure that reflects the shared usage, such as the Class Peak method. (7 TR 4601.) The Class Peak method is also the method currently used by Michigan's other large electric utility, Consumers Energy Company. (7 TR 4602.)

MI-MAUI witness Richard Bunch rebuts Staff's proposal to use the Class Peak method to allocate demand related distribution costs for the secondary voltage level. MI-MAUI witness, Bunch, claims that class peak is not an accurate and fair measure of lighting class distribution system cost causation because streetlights use the system much less than other classes, and their usage is absent during peak

periods. He does concede that an allocator based on class peak may be appropriate with respect to residential and commercial customers. (4 TR 942-943.) However, witness Bunch also takes issue with the use of allocator 300 (SIMD) for streetlighting, stating that both the use of either allocator 300 (SIMD) or Staff's proposed allocator 205 (class peak) for secondary distribution system costs will overstate the cost causation by the streetlighting class. He then argues that an adjustment to either allocation method that recognizes the low usage of the secondary distribution system by the streetlighting class is appropriate. (*Id.*) The adjustment he proposes is to allocate only primary distribution costs to streetlights, and directly allocate no secondary distribution system costs to streetlights. He states that while using a demand-based allocator will continue to allocate a disproportionately large amount of primary distribution costs to streetlighting, that will be balanced by eliminating secondary distribution costs. MI-MAUI witness Bunch testifies that his proposal would result in \$6,990,000 being allocated to other customer classes using allocator 205 (Class Peak) and \$6,170,000 using allocator 300 (SIMD). (4 TR 950.) No other party rebutted Staff's proposal.

Staff recommends the Commission approve the Class Peak method for allocating demand related distribution costs for the secondary voltage level without any special adjustments. The distribution costs being allocated are demand-related and therefore a demand-based allocator that takes into account the shared usage of the equipment costs being allocated is most appropriate. The streetlighting class utilizes the Company's distribution system and should be allocated some amount of

secondary voltage costs. Using allocator 205, the streetlighting class is assigned 0.74% of distribution costs in comparison to 65.7% for the residential class and 33.6% for the commercial class. This is also the method currently approved for use by Michigan's other large electric utility, Consumers Energy Company. Class Peak allocator 205 best reflects each class's shared use of the distribution system and should be approved by the Commission.

**B. The Commission should approve Staff's Capacity Revenue Requirement and SRM Capacity Charge.**

The Company's capacity revenue requirement method is consistent with the Commission Order in U-20836. (7 TR 4598.) The Company has removed Midwest Energy Resources Company (MERC) related expenses from its capacity cost calculation. The Company has also removed the labor costs of fuel-handling O&M from its calculation and removed MISO Schedule 17 administrative costs from being included as fuel-related costs that are subtracted from projected energy sales revenue. (7 TR 4599.) Staff recommends this method be approved by the Commission but updated with Staff's case resulting in a capacity revenue requirement of 418.7 million and an SRM Capacity Charge of \$91.6 per MW-Day.

Energy Michigan witness Alexander Zakem in his direct testimony recommends that the Commission eliminate from a new SRM capacity charge any "true-up" of previous estimates as long as DTE has not applied the previous SRM Capacity Charge to any party. (6 TR 4088.) He next recommends that if DTE does apply the SRM Capacity Charge to a party in the future, then there should be a

true-up method that adjusts the amount paid to DTE by that specific party for the difference between the net projected revenues and the fuel costs and the net actual revenues and fuel costs incurred (not “fuel-related” costs). (*Id.*) Finally, Energy Michigan witness, Zakem, proposes that, because MISO now allows a Load Serving Entity (LSE) to meet its capacity obligation by season, the payments to MISO for Planning Reserve Margin Requirement (PRMR) are by season, the payments to MISO for Zonal Resource Credits (ZRCs) are by season, and there is still no individual locational requirement for capacity imposed on either LSE’s or customers of LSEs, that section 6w of the statute and the SRM Capacity Charge should now be applied by season. (6 TR 4095.)

Company witness Adella Crozier addresses Energy Michigan’s proposal that the Commission eliminate the true-up calculation when calculating capacity charges as long as the Company has not applied the previous SRM Capacity charge to any party. Witness Crozier responds that while this proposal might make conceptual sense, the language of the enabling statute MCL 460.6w(4) states:

The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year.

Based upon the statute, Company witness Crozier does not see the requirement to include a capacity charge true-up as being contingent on whether or not an Electric Choice customer paid a capacity charge during the period being reconciled. (5 TR

2234.) Concerning Energy Michigan's proposal to administer section 6w of the statute by season and charge a seasonal SRM Capacity Charge, the Company claims that calculating rates for each season simply to change the allocation of costs between capacity and energy will create a significant and unnecessary additional burden. (5 TR 2076.) It will substantially increase the time required and create a significant challenge to break out the costs by season as there is currently no breakdown by season when projecting costs in the Company's PSCR Plan, which is currently performed on a calendar year basis. (5 TR 2077.) The Company also points out that the annual rate recovers the same costs as the rate would if computed seasonally and load serving entities all have to show capacity demonstrations for an annual period, even if broken down by season, and customers switching providers for less than a year is unlikely. For this reason, the extra effort to create seasonal rates would not be beneficial. (*Id.*)

Staff also provided rebuttal testimony in response to Energy Michigan's proposals. Concerning the SRM capacity charge true-up, Staff's position is that PA 341 does not direct the Company to true-up the capacity charge only if it was charged to a particular party, but rather the statute directs the Company to true-up the projected net revenue amounts used to calculate the capacity charge with the actual net revenue amounts that occur during the period and reflect them in the capacity charge in the subsequent year. It is Staff's position that if the Company does not do this for any reason, it would not be in compliance with Section 6w, Subsection 4. (7 TR 4607.) Staff also responds to Energy Michigan's

recommendation that if DTE does apply the SRM Capacity Charge to a party in the future, then there should be a true-up method that adjusts the amount paid to DTE by that specific party. (7 TR 4607.) Staff's position is that PA 341 does not direct the Company to true-up capacity charge payments made by specific parties during a capacity charge term, but to true-up the overall projected net revenue amounts with actual net revenue amounts for the items outlined in PA 341, Section 6w (3)(b).

*(Id.)*

Staff recommends the Commission approve the Company's capacity charge revenue requirement and SRM capacity charge calculations but updated for Staff's case. The Company's capacity revenue requirement method is consistent with the Commission Order in U-20836 and should be approved. Energy Michigan's recommendations are either unnecessarily burdensome without providing sufficient benefit or are not in compliance with PA 341.

**C. The Commission should maintain the Company's current residential customer charge.**

The Company has not proposed any changes to the \$8.50 per month residential customer charge in this case. Using the Commission approved method for calculating the residential customer charge, Staff's calculation resulted in a monthly charge of \$8.39. (7 TR 4600.) Based upon the results of the approved customer charge method, no changes are necessary to the residential customer charge. (7 TR 4601.) No other parties to this case contended this issue. Therefore,

Staff recommends the residential customer charge remain at its current level of \$8.50 per month.

**D. Staff takes no issue with the Company's allocation of the distribution related Infrastructure Recovery Mechanism (IRM) revenue requirement.**

The Company has proposed to allocate the distribution related IRM revenue requirement based upon allocation schedule 521, which is equal to each voltage classes' share of distribution related plant. (5 TR 3153.) The Company states that this allocator is appropriate because the components of the IRM revenue requirement are all plant or plant related. (*Id.*)

ABATE witness, Brian Andrews, addresses the Company's proposed IRM allocation in his direct testimony. He testifies that the Company's proposed allocation method results in transmission customers being allocated 0.772% of the IRM costs as shown on Company Exhibit A-33, Schedule X6. (4 TR 1084.) He claims that none of the investments are being made to the transmission system, and therefore, transmission level customers will have no use of the investments being proposed to be recovered through the IRM. (*Id.*) He then states that the Company has confirmed this through a response to ABATE's discovery request pertaining to the IRM and is included as Exhibit AB-1. ABATE's recommendation is that if the Commission approves an IRM for DTE, it should require the Company to remove the allocation of costs from transmission level customers who would receive no benefit from the upgrades. This is shown in ABATE's Exhibit AB-2. (*Id.*)

Staff takes no issue with the Company's IRM allocation method but acknowledges that ABATE's proposal has merit. The Company states in its response to ABATES discovery included as ABATE Exhibit AB-1 that it has not studied whether these investments will provide benefits to the transmission system.<sup>6</sup> The Company does also admit that these investments are not on the transmission system.<sup>7</sup> Because the IRM investments appear to provide no direct benefit to transmission customers, Staff recommends the Commission consider ABATE's recommendation to remove the allocation of IRM costs from transmission customers when using allocator 521.

**E. Staff's proposed change in distribution cost allocation should be implemented over time.**

Staff's proposal to allocate distribution costs on the class peak method results in a sizeable shift in revenue requirement among from the residential to the commercial secondary class and, minimally, the lighting class. (7 TR 4458.) To mitigate some of the shift in distribution revenue requirement Staff proposes to implement the full change in rates along with a credit for commercial customers and surcharge for residential customers that would both expire at the end of the test year. (7 TR 4459-4461.) Because the impact of the distribution cost allocation would be de minimis for lighting customers and due to the sheer number of different

---

<sup>6</sup> Exhibit AB-1, p 3, Response to ABATE's discovery request Question Number ABDE-1.5c.

<sup>7</sup> Exhibit AB-1, p 1, Response to ABATE's discovery request Question Number ABDE-1.5c.

credits that would need to be calculated and implemented Staff does not propose an expiring credit for that class. (7 TR 4462-4464.) Staff's proposed credit/surcharge, called IDACS<sup>8</sup>, would amount to a \$0.00221 per kWh surcharge for residential customers and a \$0.00320 per kWh credit for most commercial secondary customers. (7 TR 4661.)

The Company disagrees with Staff's proposed IDACS because it would not be possible to implement in the Company's billing system quickly enough following the final order in the instant case. The Company is also concerned that the temporary credit may confuse customers and that no additional costs for implementing the IDACS were included in the revenue requirement. (5 TR 3221-3222.) The Company recommends to not institute Staff's IDACS or, alternatively, implement half of the difference in cost allocation in the instant case and the remaining half in the following general rate case. (5 TR 3222.)

First, Staff finds it odd that the Company is fully prepared to implement 18 separate distribution surcharges for its IRM proposal yet Staff's proposed IDACS, which is made up of only 5 distinct charges, is a seemingly insurmountable challenge. Similarly, the Company did not feel the need to request any further capital or O&M expense for implementing an IRM surcharge, which would apply to virtually all customers and not just residential and commercial secondary customers. Staff argues that its IDACS proposal should not be rejected due to timing or cost if another, more complex, surcharge was also proposed by the

---

<sup>8</sup> Interim Distribution Alignment Credit/Surcharge.

Company without the same consideration. Staff concurs that implementing half of the effect of the change in distribution cost allocation would achieve the same effect as the IDACS and is thus a suitable alternative recommendation.

For these reasons the Commission and ALJ should approve Staff's recommendation to implement the effect of Staff's distribution cost allocation change with an expiring surcharge or credit for residential and commercial secondary customers, or alternatively include half of the effects of such a change in base rates with the remaining half in base rates in the Company's next general rate case.

## **F. Residential Rate Design**

### **1. Rate D1.7 should be designed to not produce a negative charge.**

Due to the shift between capacity and non-capacity-related revenue resulting from Staff's cost of service study the Company's proposed rate design method for Rate D1.7 would result in a negative summer off-peak capacity charge. (7 TR 4466.) Unintentional negative charges are problematic because they send the wrong price signal to customers. Staff proposes to design power supply charges for Rate D1.7 by allocating the rate's power supply revenue requirement to the individual charges based on their present revenue. (7 TR 4467.) Staff's method produces the appropriate power supply revenue for Rate D1.7 without the possibility of creating a negative charge.

The Company disagreed, in part, with Staff's D1.7 rate design proposal, claiming that it would distort the time variant nature of the rate design. (5 TR

3223.) To correct for this distortion the Company recommends that Rate D1.7 be designed to approximate the historic ratio of on- and off-peak charges. (5 TR 3224.) Staff concurs with this correction.

For this reason, the Commission and ALJ should approve Staff's rate design method for Rate D1.7 with the Company's recommendation that the rate maintain the historic price difference ratios between time periods.

**2. CEO's regression analysis should not be used as the basis for any recommendations.**

Staff and the Company found several deficiencies with the statistical regression analysis presented by CEO. First, CEO witness Boratha Tan describes how the results of his analysis show that some independent variables are more closely correlated to affecting the dependent variable. (6 TR 3929.) This phrasing does not necessarily mean that some independent variables *affect* the dependent variable more than others. (7 TR 4490-4491.) Second, the various regression models presented by CEO suffer from a degree of multicollinearity, where the independent variables are correlated with one another. (7 TR 4491-4493.) For example, CEO uses both area median income and poverty percentage as explanatory variables in its model, both of which measure essentially the same thing. Multicollinearity has the effect of reducing the explanatory power of the model and making it difficult to interpret its results. (*Id.*) Third, due in part to the presence of multicollinearity the models presented by CEO produce very low R-squared measures. (7 TR 4493.) This indicates that the models do not provide

much explanation for how changes in CEO's selected demographic information correlate with changes in reliability. (*Id.*) Staff suggests that there are one or more missing variables that, if included in CEO's model, would produce better results (i.e., some measure of geography or tree density.) (7 TR 4494.) The fact that some independent variables lose statistical significance with the inclusion of other independent also leads Staff to believe that CEO's models are not properly specified. (7 TR 4493.)

While Staff concurs with CEO that more rigorous statistical analysis of reliability measures with respect to demographic information is a worthwhile endeavor<sup>9</sup>, Staff does not recommend that the Commission or ALJ rely on the analysis presented by CEO in the instant case. Furthermore, some conclusions drawn by CEO from its analysis are incorrect. CEO witness, William Kenworthy, describes the correlation between the variable for Black population percentage and SAIDI backwards by stating that an increase in Black population is correlated with an increase in outage duration. (6 TR 3857.) However, in all models where the Black population percentage independent variable is significant (and not significant for that matter) the coefficient is *negative*, which indicates that a rise in the Black percent of the population is correlated with a *decrease* in the duration of interruption. (7 TR 4494-4495.)

The Company produced a report by its Supervisor of Data Science describing how CEOs models violate the basic assumptions necessary to rely on the results of a

---

<sup>9</sup> 7 TR 4494.

regression analysis. Company Exhibit A-44. The Company's report also mirrors Staff's observations that CEOs models suffer from low R-squared measures and adds discussion on technical errors present in CEOs analysis.

For these reasons the Commission and ALJ should direct the Company to work with CEO, Staff, and any other interested parties to collaborate on a more robust and statistically sound analysis regarding reliability for vulnerable communities and those that have been historically and currently are disadvantaged.

**3. DAAO's Payment Stability Pilot changes should be rejected.**

DAAO recommends that the Company's Payment Stability Pilot (PSP) be expanded to customers up to 250% of the Federal Poverty Limit (FPL). (6 TR 4002.) However, eligible low-income customers are defined by MCL 460.10t as at or below 150% of FPL for the purposes of utility low-income rates. (7 TR 4496.) For this reason, Staff recommends that the Commission and ALJ reject DAAO's proposal to expand eligibility for the Company's PSP. (*Id.*) Rather, Staff supports the on-going pilots for Percent of Income Payment Plans as effective ways to address energy affordability. (7 TR 4495.)

The Company proposes to eliminate Rate D1.6, the special low-income pilot rate that offers a \$40.00 monthly bill credit, and instead add a low-income pilot provision to other residential rates. (5 TR 3200.) This proposal would allow customers receiving the pilot bill credit to take service on the spectrum of rates otherwise available to them. DAAO recommends to only allow the Company to

eliminate Rate D1.6 on the condition that the Company consolidate all energy assistance programs into a single program for residential customers at or below 250% of FPL. (6 TR 4002.) However, DAAO did not actually propose such a consolidation, but rather that the Company analyze combining its low-income programs. (6 TR 4001.) Because DAAO did not actually recommend their prerequisite to eliminating D1.6 and Staff discussion on the infeasibility of expanding low-income programs to customers at or below 250% of FPL under current state law the Commission and ALJ should reject DAAO's proposals and approve the Company's elimination of Rate D1.6 and addition of the special low-income assistance credit to the remaining residential rate schedule tariffs.

#### **G. Commercial and Industrial Rate Design**

##### **1. Power supply demand and energy charges for Rates D4, D11, and D6.2 should be set to their historical ratios.**

The Company proposes to limit the change between the proportion of revenue recovered via demand charges versus energy charges by 15% for Rate D4, D11, and D6.2. (5 TR 3110 and 3113.) The Company did not elaborate on the purpose of this limit in its initial filing and framed the discussion as if the balance between energy and demand charges was a naturally occurring phenomenon. (7 TR 4472-4473.) It occurred to Staff that the Company proposed to alter the relationship between power supply demand and energy charges for the affected rates but described the process as something other than that. (*Id.*) Because the Company failed to describe why the limit was necessary, and thus breaking with previously approved rate

design, Staff recommended to fix the proportion of power supply revenue derived from energy charges and demand charges to that of presently approved rates. (7 TR 4474.)

In its initial filing the Company states that it does not take a specific position on the right balance of demand to energy charges. (5 TR 3113.) It is inappropriate for the Company to not take a position but also propose a 15% limit *on the position it is not taking*.

On rebuttal it became clear that Staff's interpretation of the reasoning behind the Company's proposal was incorrect, but that does not mean said reasoning is correct. (7 TR 4489.) According to ABATE, Kroger, and the Company the split between power supply energy and demand charges should be dictated by the State Reliability Mechanism (SRM) capacity charge. (4 TR 1085-1086, 6 TR 4286, and 5 TR 3120 respectively.)<sup>10</sup> ABATE witness, Brian Andrews, summarizes the issue at hand:

It first makes sense to discuss the power supply components of Rate D11. There are three primary components. The Capacity Demand Charge, which recovers the portion of the allocated power supply revenue requirement that has been deemed "capacity-related" due to the SRM Capacity Charge calculation. The second component is the Non-Capacity demand charge, which historically has been used to recover the allocated transmission expense. Finally, there is the Non-Capacity energy charges, which recover the remainder of the allocated power supply revenue requirement. The SRM capacity charge up to this point has been used to determine the D11 Capacity

---

<sup>10</sup> Company witness, Matthew F. Pollack, was incorrect that Staff witness, David W. Isakson, "characterizes the current ratio between demand and energy as 53% / 47% demand / energy; it should read 47% demand and 53% energy." Line 7 of 7 TR 4474 clearly refers to Rate D4, which does in fact produce 53% of present revenues from demand and 47% from energy charges. *Rate D11 produces the inverse ratio*, which is likely from whence Company witness Pollack's confusion stems.

Demand Charge. The SRM capacity charge does not impact the overall costs that are allocated to classes, but rather how those costs are separated into “capacity” and “non-capacity” buckets. If the SRM Capacity Charge goes down, then the costs that are put into the “capacity” bucket goes down and the “non-capacity” bucket would increase by the same amount. For D11, when the SRM Capacity charge goes down, the D11 Capacity demand charge decreases, which would then force the non-capacity demand and/or energy charges to increase.” (4 TR 1092, internal citation omitted.)

Staff concurs that the method used to determine the SRM capacity charge should not necessarily inform rate design. This is made clear by its effect on rate design and the Company’s position to limit that effect.

The Company and Kroger argue that the rate design method described by ABATE—using the SRM capacity revenue to determine the demand charge and non-SRM-capacity revenue to determine both demand and energy charges—has been used and approved for a number of cases. (5 TR 3120 and 6 TR 4291.)

It is not, however, appropriate to rely on previous Commission-approved rate design methods when those methods produce a result like the substantial shift between demand and energy charges as proposed by the Company, limited or otherwise.

Kroger argues that Staff is confusing the “deviations from the Commission approved rate design *methodology* with changes to the *values* of the various rate components.” (6 TR 4299.) In other words, Kroger is partially correct when describing Staff’s objection to the Company’s 15% limit proposal, but since Staff was elucidated via rebuttal testimony there are now two distinct parts to Staff’s argument. First, Staff determined that the limit was contrary to Commission-approved rate design and should be rejected. (7 TR 4474.) Kroger is correct in its

assessment of this part. (6 TR 4300.) Second, the Commission-approved rate design method produced results that were so different from previous rate designs that relying on that method would create substantive inappropriate effects on customers and should therefore be changed.

In other words, Staff is less concerned with the *amount* of the limit than the need for one in the first place. In effect, Staff's proposal "limits" the shift between the two charges to zero. The reasons for Staff's proposal are as such: the determination of SRM capacity costs is *only* meant to inform the process of billing alternative energy suppliers for those costs when appropriate and not to determine the overall capacity and energy split for rate design. This is to avoid volatile wholesale energy prices which affect the statutory determination of the SRM also affecting regulated utility rate design because of that same volatility. (4 TR 1090-1091.) That the Commission-approved method produced the results at hand means that method should be altered not by inducing a limit, but by rejecting the shift, and the rate design method that created it, whole cloth.

Staff does not concur with ABATE's primary proposal nor its provided support that 62% of power supply costs be recovered via demand charges and the remaining 38% through energy charges. (7 TR 4490.)

ABATE argues that variable cost items should be recovered via energy charges and fixed costs via demand charges. (4 TR 1094.) This argument lacks nuance as it pertains to the effects of load diversity within the customer classes. Load diversity can lead to more efficient design of the distribution system because

not all customers' individual peak loads will coincide, thus the Company does not necessarily have to supply power as if they do. (7 TR 4488-4489.) Also, fixed costs rarely remain fixed in the long run. The whole purpose of a cost-of-service study is to tease out the contribution to shared costs of various customer classes, and not just to deem them fixed or variable. Finally, all demand-related costs are not *actually* fixed because they can *vary* with demand even in the short run. (*Id.*)

ABATE's alternative recommendation is identical to Staff's primary recommendation and thus Staff supports it to set the demand and energy power supply revenue recovery for Rates D4, D11, and D6.2 to the same ratio as that found in present revenue. (4 TR 1096 and 7 TR 4474.) For these reasons the Commission and ALJ should rejected the Company's proposed limit to the shift between demand and energy charges for primary rate design and approve Staff's recommendation to retain the historical relationship between them.

**2. EIBC/IEI/United's proposal to establish time-of-use TOU rates for primary and secondary customers should be rejected in part.**

EIBC/IEI/United proposes to create an optional rate for primary and secondary voltage level customers that mirrors the TOU parameters offered on residential Rate D1.11 including a flat energy charge for distribution.

EIBC/IEI/United supports this proposal by describing the Company's lack of TOU options for these customers as well as its perceived faults of demand charges in general. EIBC/IEI/United describes TOU rates for primary and secondary

customers as beneficial because they better reflect the benefit of load diversity among customers. (6 TR 4243-4244.)

Staff concurs with EIBC/IEI/United that the Company should offer a TOU rate to primary and secondary customers but disagrees that mirroring the exact structure of residential Rate D1.11 is appropriate. (7 TR 4497.) Specifically, Staff is unconvinced that distribution costs under a TOU rate structure for primary customers should be recovered through a flat energy rather than a peak demand charge. (7 TR 4498.) Staff agrees that power supply TOU charges can reflect the benefit of load diversity. On the other hand, load diversity does not preclude the possibility that customers' peak load will occur at the same time as the system peak, nor that large customers can influence their class peak load, thus impacting their cost causation. (*Id.*) Staff also notes that distribution costs are allocated to classes on demand in the COSS, and thus matching allocation with the type of charge in rate design is often optimal when possible and not made inappropriate by the impact of load diversity. (*Id.*)

Secondary customers do not currently pay a distribution demand charge, so Staff does not recommend that one be applied to a secondary TOU rate should the Commission approve EIBC/IEI/United's proposal. (*Id.*)

EIBC/IEI/United also discusses that Consumers Energy offers primary and secondary TOU rates with pricing components similar to those in its proposal, but the Consumers Energy rates include more pricing windows and a distribution demand rate for primary customers. (6 TR 4248.) Staff posits that applying the

Consumers Energy rate scheme for primary and secondary TOU rates is the most appropriate path for implementing EIBC/IEI/United's proposal, including the retention of distribution demand charge for primary customers. (7 TR 4499.)

Finally, Staff disagrees with the timing of the implementation of EIBC/IEI/United's proposal. EIBC/IEI/United recommends that the Commission direct the Company to establish TOU rate options for primary and secondary customers within 30 days of a Commission order. (6 TR 4250.) EIBC/IEI/United did not actually include a calculation of its new rate proposal, so Staff, the Company, and intervenors could not evaluate the actual charges that such a design would create. Nor could parties to the case determine that the rate proposal would generate the correct revenue nor provide opportunity to dispute the technical machinations of the rate design. (7 TR 4499.) The Company would effectively have to interpret the Commission's decision, file rates according to that interpretation, and preclude review by any other party except the Commission all within the same month during which they already must update all other rates. (*Id.*) It would be more feasible and appropriate for the Commission to direct the Company to provide in its next rate case new rate schedules for primary and secondary customers based on Consumers Energy's rates GPTU and GSTU but with a 2-part seasonal TOU structure for power supply charges. This way all parties to the case would have ample time to evaluate the new rate proposal and allow the Company to include any implementation costs into its revenue requirement.

The Company argues that “It would be no more appropriate to unilaterally apply primary voltage rate design to residential customers than Witness Barnes’ proposal to unilaterally apply residential rate design to primary voltage customer.” (5 TR 3236.)

The Company lists five conflicting points of EIBC/IEI/United’s request for a D1.11-type rate structure for primary customers that the Company argues show that EIBC/IEI/United provides an inconsistent narrative on what an appropriate TOU rate design for secondary and primary customers should entail. (5 TR 3238.) In defense of demand charges, the Company argues that they are appropriate for high load factor customers because they tend to utilize a larger portion of their peak demand at other times during the month, so a purely TOU rate scheme would mean lower revenues from those customers, thus burdening the remaining lower load factor customers with increased costs. (5 TR 3238-3239.)

The Company disputes EIBC/IEI/United’s framing of the Company’s current rate offering as lacking optionality and that certain rates fail the goal of broad adoption. The Company notes that it offers primary and secondary rates with options for TOU pricing, critical peak pricing, two types of interruptible load options, and, for commercial customers, a flat rate option. (5 TR 3239-3240.) As for broad adoption, the Company clarifies that the term was meant to refer to offering rate options without second meter requirements whenever possible, which can erect a barrier to entry to some rate options. (5 TR 3241.)

Finally, the Company finds that it is unreasonable to implement EIBC/IEI/United's proposal within 30 days of the final order in the instant case. While Staff argues that the time limit suggested by EIBC/IEI/United would not allow enough time for actual design and analysis of the rate proposal the Company states that it is unable to complete the technical requirements necessary to implement a brand-new rate in that time. (5 TR 3241.)

For these reasons Staff recommends that the Commission and ALJ reject EIBC/IEI/United's proposal to establish new TOU rates. Staff recommends that the Commission and ALJ direct the Company to, in its next rate case, propose a rate structure for an optional primary and secondary TOU rate as described by EIBC/IEI/United but retain the distribution demand charges of Rate D4 and D11.

### **3. Rider 10 Administrative Charge**

The Commission previously directed the Company to either provide justification for the R10 administrative charge or to eliminate it. (7 TR 4476.) The Company did neither and instead proposes a negative administrative charge for Rider 10 (R10). (Company Exhibit A-16, Schedule F3, page 42.) As discussed for the rate design for Rate D1.7, unintentional negative charges are inappropriate because they distort the price signal intended for customers. That the Company's proposed administrative charge is negative because the rate is due a proposed decrease in non-capacity power supply costs only highlights the disconnect between the name "administrative charge" and what costs it actually recovers (or *refunds* per this discussion.) Staff witness David Isakson proposed to set the administrative

charge to zero and fully recover the allocated non-capacity power supply costs through the MISO energy charge. (7 TR 4477.) Staff further recommended that the Commission direct the Company to submit in its next rate case actual data on the cost of administering R10.

In rebuttal the Company explained that the negative costs being recovered in the R10 administrative charge actually derive from the rider's income sufficiency grossed up for taxes. (5 TR 3158-3159.) The Company then proposes a better solution to addressing the administrative charge spreading the impact of the tax grossed-up amount to all other customers and remove it from R10 customers. This would not impact the overall revenue requirement and make the R10 production revenue requirement equal to its cost of transmission, MISO energy, and the voltage level service adder. The Company also discovered an error in the calculation of present revenue for R10. Staff agrees with the Company's proposed solution to arriving at a zero administrative charge for R10 and Staff also confirms the error in R10's present revenue calculation.

For these reasons Staff recommends that the Commission and ALJ approve the Company's approach to set the administrative charge for Rider 10 to zero by reallocating the tax grossed-up income sufficiency to other customers and to correct the error in Rider 10 present revenue in its final order.

The Company disagrees with Staff's recommendation to require the Company to submit data detailing the actual cost to administer R10 in its next rate case. The Company explains that they do not, as a general matter, perform the cost-of-service

study through allocation of specific line-item costs. (5 TR 3160.) The Company also disputes that the costs identified by Staff as possibly related to administering R10 are actually distribution-related costs. (*Id.*) The Company recommends that the Commission reject Staff's proposal to require the Company to include actual administrative costs for Rider 10 in its next case. (5 TR 3228.) Because the Company's proposal results in a zero administrative charge and it has been determined by the Company and Staff that the proposed negative administrative charge is only composed of a tax gross-up for income deficiency/sufficiency Staff withdraws its proposal to require administration costs be submitted in the Company's next case.

## **H. Lighting Rate Design**

### **1. General lighting adjustment**

The Company's lighting rate design model includes a highly detailed breakdown of costs for each type of luminaire and type of lighting service including a separate interpolation model that "fills in the blanks" for certain luminaire rates. Staff's adjustments to rate base and O&M mostly affect general plant or administrative O&M as it applies to lighting customers, which is not easily incorporated into the Company's highly specific lighting rate model. The effects of Staff's revenue requirement affect all lighting rates generally, so Staff makes a small adjustment to all lighting rates generally. This adjustment does not change the lighting class revenue requirement, but rather allows it to be neither over- nor

under-collected. Without such an adjustment the lighting class would not produce the correct revenue required as determined by the COSS. (7 TR 4480.)

For this reason, Staff recommends the Commission and ALJ permit Staff's generalized adjustment to lighting rate design in order to properly collect the lighting class's revenue requirement.

## **2. MI-MAUI lighting revenue requirement proposals**

MI-MAUI makes several recommendations affecting lighting class revenue requirement, with which Staff disagrees only with regard to how those recommendations could affect non-lighting customers. Specifically, MI-MAUI recommends a reduction in lighting revenue requirement of \$332,524 for overspending on LED lamps, that a portion of lighting outage credits be paid by the Company, and that the lighting load forecast be reduced to reflect known outages plus reduce the lighting revenue requirement accordingly. (4 TR 920, 937-938, 940.)

Staff does not take a position on the first two recommendations themselves, but rather how they may affect non-lighting customer revenue requirement. Staff recommends that any adjustment that the Commission approves to the lighting class should not cause a change in the revenue requirement for any non-lighting class. That is, a reduction in lighting revenue requirement should not be followed by an equal but opposite change in overall revenue requirement for other customers. (7 TR 4501.) Adjustments to the lighting revenue requirement or load forecast should be done through the typical method of enacting adjustments without extra impact to other customers. For example, a change to the lighting sales

forecast would necessarily flow through the forecast model, COSS, and finally rate design and by the nature of those models already produce the appropriate impact on revenue requirement for all customers so no additional adjustment would be necessary. This is largely an argument of semantics on behalf of Staff, but one that is nonetheless necessary. (7 TR 4502.)

Staff agrees with MI-MAUI's proposal to adjust the lighting sales forecast, but not the recommendation to "reduce the revenue requirement for streetlights accordingly." (4 TR 940.)

## **I. Other Issues**

### **1. DAAO's Payment Stability Pilot changes should be rejected.**

DAAO recommends that the Company's Payment Stability Pilot (PSP) be expanded to customers up to 250% of the Federal Poverty Limit (FPL). (6 TR 4002.) However, eligible low-income customers are defined by MCL 460.10t as at or below 150% of FPL for the purposes of utility low-income rates. (7 TR 4496.) For this reason, Staff recommends that the Commission and ALJ reject DAAO's proposal to expand eligibility for the Company's PSP. (*Id.*) Rather, Staff supports the on-going pilots for Percent of Income Payment Plans as effective ways to address energy affordability. (7 TR 4495.)

The Company proposes to eliminate Rate D1.6, the special low-income pilot rate that offers a \$40.00 monthly bill credit, and instead add a low-income pilot provision to other residential rates. (5 TR 3200.) This proposal would allow

customers receiving the pilot bill credit to take service on the spectrum of rates otherwise available to them. DAAO recommends to only allow the Company to eliminate Rate D1.6 on the condition that the Company consolidate all energy assistance programs into a single program for residential customers at or below 250% of FPL. (6 TR 4002.) However, DAAO did not actually propose such a consolidation, but rather that the Company analyze combining its low-income programs. (6 TR 4001.) Because DAAO did not actually recommend their prerequisite to eliminating D1.6 and Staff discussion on the infeasibility of expanding low-income programs to customers at or below 250% of FPL under current state law the Commission and ALJ should reject DAAO's proposals and approve the Company's elimination of Rate D1.6 and addition of the special low-income assistance credit to the remaining residential rate schedule tariffs.

## **2. Tariff implementation**

Staff found the Company's presentation of amendments to its tariffs as "for discussion" to be unusual. Rather than seek Commission approval for changes to the Company's tariffs as they relate to the Company's proposals to eliminate Rate D1.6 (special low-income pilot), create Rate D1.13 (overnight savers), and expand availability of the low-income pilot credit and senior citizen credit the Company proposed to file these tariffs at a later date or in a separate case. Staff recommends that the Commission approve these tariff amendments in the instant case, direct the Company to file said tariffs within the typical 30-day period following the final order, and include additional language noting the effective date of the proposed

amendments before the end of the test year. (7 TR 4480-4483.) The Company agrees to Staff's proposal for the approval of these tariff amendments on rebuttal. (5 TR 3225.)

For these reasons the Commission and ALJ should approve the Company's proposed tariff amendments regarding the low-income pilot credit, senior credit, and Rate D1.13 and require the Company to file tariff language describing the effective date of these provisions before the end of the test year.

### **3. Other Tariffs**

Staff recommends that the Commission deny the Company's PrePay pilot proposal, as discussed elsewhere in this brief. (7 TR 4551-4557.) Therefore, Staff also recommends that any tariff amendment requested by the Company to implement its PrePay pilot also be denied; specifically, under the availability section of residential Rate D1.

### **J. Considerations for future rate cases**

The Company failed to include all necessary workpapers required to complete a thorough auditing of its proposed rate design model. (7 TR 4483.) Specifically, the Company did not submit as part of its initial filing the workpaper necessary to calculate billing determinants used in rate design. This data is crucial to the calculation of every single rate ultimately approved by the Commission as it represents the denominator for the basic math of rate design (a charge is essentially a specific revenue target divided by the corresponding billing determinant). In

practice the absence of billing determinant workpapers means critical information was “hardcoded” into the rate design model which makes auditing the Company’s case nigh impossible. How are Staff or the Commission to determine the providence of, say, the number of off-peak winter capacity kWh for Rate D1.2 when the only information provided by the Company in its initial filing is the number 84,070.312 typed directly into a cell in an Excel spreadsheet? Staff ultimately received the supporting calculations used to determine these crucial billing determinants via audit response the fact of the matter is that Staff never should have had to make such a request. (7 TR 4483-4484.)

Staff reminds the Company, and requests the Commission do the same, that per state law “The utility shall place in evidence facts relied upon to support the utility’s petition or application to increase its rates and charge, or to alter, change, or amend any rate or rate schedules.”<sup>11</sup> (7 TR 4484.)

Staff respectfully asks the Commission to confirm that there are consequences if the Company does not provide all necessary, fully functional, and auditable workpapers and complete and accurate data required to calculate and approve its request.

**1. The DG tariff should not compensate for societal benefits.**

DAAO witness Koepfel testified that DG should be compensated for societal benefits (6 TR 4046). Staff responded that societal benefits may take legislation to

---

<sup>11</sup> MCL 460.6a(1).

implement and would cause the costs to utility customers to increase (7 TR 4542). Staff recommends that societal benefits, such as health and climate, continue to not be compensated through the DG tariff, as is currently the case. DG compensation for social benefits should therefore be rejected.

**2. Incorporation of testimony by reference should not be permitted.**

DAAO witness Koeppel requested to incorporate, by reference, testimony from previous cases (6 TR 4046.) Staff responded that if this is allowed then Staff would like to also incorporate, by reference, all previous testimony and rebuttal testimony on related subject matter. (7 TR 4542.) Staff recommends that all incorporation by reference should be rejected but reserves the right to refer to records of previous cases in reply brief if other parties refer to testimony from previous cases in their initial brief.

**3. Rider 3 does not discriminate against PURPA QFs**

MEIBC witness Hoyle says that Rider 3 discriminates against PURPA QFs because it charges them more than they would have been charged on another tariff. (6 TR 4226-4227.) Staff explains that Rider 3, in most circumstances, charges less than the customer would have been charged on their base tariff on an annual basis. (7 TR 4539-4540). Staff recommends that the Commission approve Rider 3 as non-discriminatory toward PURPA QFs and reject MEIBC arguments to the contrary.

**4. Bloom Energy's Rider 3 proposals should be rejected.**

Bloom Energy, through its witness, Douglas Jester, recommends several changes to the large self-generation tariff known as Rider 3. (6 TR 4120-4138). Staff responds in rebuttal that arguments which are valid for generation are not necessarily valid for distribution. (Krause, 7 TR 4540-4541.) Most notably, generation tends to be central and easily used by other customers and distribution tends to be local and can be shared with local customers, but not by customers far away. (Krause, 7 TR 4541). Furthermore, these arguments have been made, and rejected, previously and are not accompanied by calculations or redlined tariffs, thus making the proposal difficult to evaluate. (Krause, 7 TR 4541). For these reasons, Staff recommends rejecting the proposals by Bloom Energy for Rider 3.

**5. Compensating Battery or Vehicle to Grid exports at full retail should be rejected.**

MEIBC witness, Sherman, states that batteries are not economic unless they can be compensated at full retail for outflow. (6 TR 4157). MNSC witness, Douglas Jester, makes similar arguments. (6 TR 3468). Staff responded in rebuttal stating that battery and V2G exports do not offset distribution and should not be compensated as such. (Krause, 7 TR 4538). Furthermore, such a tariff may result in exports at a time when exports would not be supportive of the grid. (Krause, 7 TR 4539). Staff suggested a more appropriate tariff for battery and V2G exports would be designed like a demand response tariff. (Krause, 7 TR 4539). For these reasons, Staff recommends that compensating battery or V2G exports at full retail be rejected.

**6. The demand charge holiday should be extended and a rolling demand charge holiday should be implemented.**

Staff testified that demand and infrastructure are correlated. (Krause, 7 TR 4526). Staff also showed that charging is trending to be faster. (Krause, 7 TR 4526). Faster charging results in increased demand and therefore requires more infrastructure and therefore causes more costs. (Krause, 7 TR 4526). These points were undisputed by any party.

MEIBC witness, Laura Sherman, took issue with demand charges for fast charging, calling them “onerous.” (6 TR 4175, 4197). Similarly, Walmart witness, Lisa Perry, called demand charges a “barrier.” (4 TR 1047). Whether or not demand charges are onerous or a barrier is of less concern to Staff than they be based on the costs to serve customers. (Krause, 7 TR 4535-4536). It is worth noting that nowhere did these witnesses state that demand charges were not based on cost causation, only that they would prefer chargers be on a rate without a demand charge.

MEIBC witness, Sherman, also proposed that separate rates be developed for EV charging. (6 TR 4155). As a response to this proposal, Staff suggested that a separate cost-of-service study should be produced that allocates all appropriate costs to fast charging and designs rates specific for this class of customer (Krause, 7 TR 4535-4536). If fast chargers are less costly to serve, as witness Sherman surmises (6 TR 4195-4196), then placing them in a separate cost-of-service class and calculating specific rates will confirm this hypothesis.

Despite the evidence that demand charges for fast charging would be appropriate for sites above 1,000 kW in demand in the long term (Krause, 7 TR 4538), Staff still recommends that fast charging on Rate D3, which has no demand charges, is appropriate until June 1, 2026. (Krause, 7 TR 4529, 7 TR 4537-4548). One reason being that the pandemic has interfered with infrastructure implementation. (Krause, 7 TR 4529). Additionally, Staff recommends that fast charging stations installed after June 1, 2024, be allowed to operate on Rate D3 for a period of two years after installation, subject to review in future cases. (Krause, 7 TR 4529). MEIBC agreed to this proposal (6 TR 4198), while it would appear to conflict with the proposal of Walmart to make the demand charge holiday permanent. (Perry, 4 TR 1047-1048).

To summarize, Staff recommends an extension of the demand charge holiday and the implementation of a rolling demand charge holiday. Staff additionally recommends that if new distinct rates for EV charging are desired by the Commission that they should direct the Company to file an alternative cost-of-service study with DC fast charging included as a separate rate class.

## **7. Demand charges for DC Fast charging send a price signal for reliability**

In direct testimony, Staff witness Kevin Krause states that demand charges send a price signal for reliability. (7 TR 4528-4529). They accomplish this by charging more to the charging point operator for service when their station is offline. (Krause, 7 TR 4528). MIEBC witness, Sherman, states that demand

charges may or may not incentivize reliability and that other means may be necessary. (6 TR 4196-4198). Staff agrees that other means may be necessary but maintains that it is clear that a charging point operator on an energy only tariff will pay less when their station is offline (Krause, 7 RE 4528-4529). Therefore, Staff recommends that the Commission acknowledge that DC fast charging rates with demand charges do more to incentivize reliability than energy only rates.

**8. EV programs should be designed to maximize ratepayer benefits**

MNSC witness, Douglas Jester, states that EV programs funded by the Company through customers should be designed to maximize societal benefits. (6 TR 3473). The AG through witness Coppola states that EV programs should not be funded by the Company at all after 2023. (6 TR 3725-3727). Staff responds that EV programs should maximize customer benefits. (Krause, 7 TR 4532). Staff states that societal funding, such as state and local taxes, be used to achieve societal benefits. (Krause, 7 TR 4532). Therefore, the Commission should order that EV programs be designed to maximize ratepayer benefits.

**9. Permanent EV programs should support maximizing ratepayer benefits.**

MNSC witness, Jester, supports in his direct testimony making several EV programs permanent in the next rate case. (6 TR 3465). Staff opposes in part. In the rebuttal testimony of Staff witness, Kevin Krause, Staff points out that programs which are not capable of providing a net benefit to ratepayers on their

own will reduce the net benefits of the overall EV program. (Krause, 7 TR 4536). When several paths are possible it is important to set a path that attempts to maximize ratepayer benefits. (Krause, 7 TR 4536). Staff goes on to point out that, generally speaking, the programs that provide the greatest benefit to utility customers are the programs that incentivize off-peak charging. (Krause, 7 TR 4546-4537). Staff recommends that permanent components of the EV program should provide net ratepayer benefits in order to support the goal of maximizing the ratepayer benefits of the overall EV program.

**10. Staff recommends approval of submetering on rate D3 for customers on rate D4, but not for customers on other rates at this time.**

In its application, the Company requested submetering on rate D3 for customers on rate D4 through its witness, Kelsey Peterson. (4 TR 715). Staff agreed with the request subject to the demand charge holiday recommendations. (Krause, 7 TR 4530). MEIBC witness, Sherman, stated in direct testimony that the provision should be extended to submetering on other rates. (6 TR 4155). Staff responded through the rebuttal of Kevin Krause that they were unsure whether it was appropriate to extend submetering on a secondary rate to primary customers. (7 TR 4535). Staff recommends that the Commission approve submetering on rate D3 for customers on rate D4 subject to the demand charge holiday, but that submetering on D3 for other rates not be approved at this time.

**11. Not all distribution upgrades for EV charging should be socialized.**

MNSC witness Jester states in direct testimony that all distribution upgrades for EV charging should be socialized. (6 TR 3473). Staff disagrees. In rebuttal testimony, Staff states that it is reasonable to set limits on customers charging demands so that they do not overburden the distribution system. (Krause, 7 TR 4533). Charging above these limits it is reasonable to expect customers to contribute to distribution upgrades. Staff recommends limits for residential charging (Krause, 7 TR 4533), and states that limits for other rate classes should be examined in the future. (Krause, 7 TR 4533). Staff recommends that all distribution upgrades should not be socialized and that limits are appropriate.

**12. Rate D3 provides reasonable flexibility for EV charging.**

In direct testimony MIEIBC witness, Laura Sherman, expresses concern with the sunset of the D3 provision that Staff calls a demand charge holiday, stating issues with NEVI funding for DC fast chargers and level 2 workplace charging. (6 TR 4154). Staff responds that the NEVI example given would allow the NEVI site to remain on rate D3, even after the sunset. (Krause, 7 TR 4533-4535). Furthermore, for workplace charging 100 Level 2 stations of 9.6kW would be able to charge on rate D3 after the sunset. (Krause, 7 TR 4534). Staff finds that 100 Level 2 stations at a workplace is sufficient at this time. (Krause, 7 TR 4534). Staff also points out that using storage or load management software that higher demand sites could also remain on rate D3. (Krause, 7 TR 4535). Staff recommends that

these arguments against the demand charge holiday and the alleged relationship between rates D3 and D4 be rejected.

**13. The Company's proposed Community Charging tariff language should be rejected.**

As Staff recommends that the Community Charging proposal not be approved, the associated tariff language proposed by the Company should also be rejected.

(Krause, 7 TR 4530.)

**VII. Distributed Generation and Demand Response**

**A. Staff Recommends the Company be directed to update Demand Response (DR) tariffs to clarify customer eligibility to participate with DR aggregators.**

The Company should update its DR tariffs to include language that specifies which program's customers are ineligible to participate with a DR aggregator and for which MISO seasons that ineligibility applies. MEIBC Witness, Kenneth D. Schisler, proposed this recommendation (6 TR 4259-4260) to help prevent resources from being double counted by participating in both utility and demand response aggregator programs. Both Staff (7 TR 4388-4389) and the Company (5 TR 1335-1336) agree with MEIBC that adding language to this effect may help to avoid resources being double counted and/or reduce the burden on the registration review process to identify and remove those double counted resources. The Company proposes adding "Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC)" to each interruptible tariff (5 TR 1335-1336). In order to align

with the February 23, 2023, Commission Order in Case No. U-21099, which directed utilities to “object to ARC DR registrations that include load that is currently participating in any utility DR program for a particular season but shall allow participation of this load for seasons not covered by the utility tariff or DR program” the Company’s proposed language should be modified to include whether this ineligibility applies to all four seasons within MISO resource adequacy construct and, if not, specify which seasons are eligible/ineligible.

**B. The Commission should reject the other DR tariff changes recommended by MEIBC.**

MEIBC Witness, Schisler, recommended two other DR tariff changes related to DR aggregation. Those recommendations were to propose new, or modify existing, tariffs to unbundle wholesale and retail benefits, products, and services and to direct DTE to work with DR aggregators to develop and propose a DR feed-in-tariff. (6 TR 4269.) The Commission should reject both recommendations.

The recommendation to develop new, or modify existing, tariffs to unbundle wholesale and retail benefits, products, and services should be rejected because it is unclear what this unbundling process would entail, how it would be calculated, and the potential consequences. (7 TR 4389-4390.) The Company agrees with Staff that this proposal should be rejected. As stated by the Company, the Company’s DR programs’ benefits, products and services are utilized at the wholesale level for its retail customers. The Company does not have any wholesale customers. The

Company's DR programs are designed to support the reliability of the bulk electric system. (5 TR 1337)

The recommendation to develop a feed-in-tariff should be rejected because there are more efficient and cost-effective methods for the Company to procure additional DR resources from third parties, when suitable. Designing a feed-in-tariff that compensates DR resources reasonably and delivers the needed amount of resources is impractical. A feed-in-tariff is likely to either overcompensate DR resources, leading to the procurement of more resources than might be necessary and/or to those resources costing the ratepayer more than they otherwise would have, or undercompensate DR resources, leading to fewer resources procured than what was needed or planned. (7 TR 4390) Other options that are available for the Company to procure DR resources from aggregators include participation in utility all-source competitive solicitations, special solicitations for DR resources such as the 150 MW of new DR included in the most recent DTE IRP settlement,<sup>12</sup> and aggregators submitting alternative proposals in certificate of necessity cases. DR aggregators can also be compensated for DR capacity through participation in the MISO planning resource auction, without selling capacity bilaterally to utility companies. The Company agrees with Staff that a DR feed-in-tariff is not needed and points to the already existing ability of the Company to purchase DR capacity through the MISO resource adequacy construct. (5 TR 1339)

---

<sup>12</sup> Case No. U-21193 Settlement Terms 18b. Approved July 26, 2023, Commission Order.

## VIII. IRM

The Commission should approve the Company's proposed IRM, with modifications.

DTE is proposing a roughly three-year distribution infrastructure recovery mechanism (Distribution IRM) that would begin on December 1, 2023. The Company is proposing that the first year of the IRM extend for 13 months such that it encompasses all of December 2023 and calendar year 2024. (5 TR 2733).

Subsequent IRM plan years would be aligned to calendar years. The Company proposes to include five programs in the initial iteration of the Distribution IRM:

1. Circuit Conversions, including both City of Detroit Infrastructure (CODI) and non-CODI conversions;
2. Sub-transmission Redesign and Rebuild;
3. Breaker Replacement;
4. Underground Residential Distribution (URD) Replacement; and
5. 4.8 kV Circuit Automation.

(2 TR 64.)

These programs were selected because the Company believes they are critical to customer safety, reliability, and/or resiliency, they are of sufficient size and duration, and they have a well-understood scope. The Company is proposing that the full proposed projected test-year program investment be authorized for IRM treatment starting in year one for the Breaker Replacement, URD Replacement and 4.8 kV Circuit Automation Programs. For the Conversion and Sub-Transmission Redesign and Rebuild programs the Company is proposing that only a portion of the

proposed projected test-year program investment be authorized for IRM treatment in Years 1 and 2.

Numerous parties oppose the IRM. The AG and MNSC recommend that the Commission reject the Company's request. Witness Paul Alvarez states that for programs and projects in distribution grid investment plans presented in advance, regulatory lag is the only remaining brake on utility spending and if the Commission approves the IRM as DTE proposes, it will eliminate that brake. (6 TR 3341). He states that frequent rate case applications are one way that the utilities can reduce regulatory lag. He also states that the Company seems to file a rate case annually, making regulatory lag appear to not be a problem that requires special cost recovery. (6 TR 3342.) He recommends that the Commission establish an expectation that no rider cost recovery request be considered from any utility on distribution investment until a distribution planning process that restores capital spending governance and mitigates information asymmetry be implemented. *Id.* Witness Dennis Stephens agrees that the Commission should reject the Company's IRM, however he also recommends limits to the use of the IRM if the Commission chooses to approve the mechanism. His limits include that capital recovered under the IRM be limited to \$353 million. (6 TR 3408.) This is the amount of the distribution grid plan not already spent, not recommended for disallowance, and not recommended for IRM cost recovery in this case.

ABATE recommends the Commission reject the Company's request for an IRM. Witness York supports the Company's desire for increased accountability and

transparency with respect to its strategic capital programs, but states that these objectives can be achieved without the IRM. (4 TR 1142.) Witness York states that the Company should already be transparent in its general rate cases for the Commission, Staff, and other intervenors to assess the programs the Company wants to include in rates. Witness York also states that the Company's argument for increased accountability due to the proposed reporting metrics is not necessary to implement an IRM. The Company could track and report metrics to assess the execution of the Company's investment plans without the IRM in place. (4 TR 1143.) Witness York also states that the five programs included in the IRM are reasonably certain to occur and can be planned for and included in base rates. *Id.* Witness York also states that this request is an example of single-issue ratemaking and the Company's proposed method of calculating the IRM incremental revenue requirement ignores the offsetting reduction in the value of plant investment included in base rates. (4 TR 1144.) If the Commission does approve the IRM, Witness York suggests that the Commission ensure that DTE's investment included in base rates is synchronized with the incremental eligible investment that would be subject to the IRM. *Id.* Witness Brian Andrews argues that because all these investments in the IRM are being made to the sub-transmission or lower voltage system, the costs should not be allocated to transmission level customers who would receive no benefit from the upgrades.

Despite these criticisms, Staff supports the Company's Distribution IRM proposal, as it will help ensure continued investment in DTE Electric's distribution

system. However, Staff recommends certain modifications. In witness Neal Foley's testimony on page 27, he states that:

[T]he Company proposes that no later than two months prior to the start of each IRM Plan Year it submits to Staff an "IRM Investment Plan" for the upcoming year. This timing is consistent with the DTE Gas IRM. At that time Staff would have the opportunity to review the Company's investment plan and raise any questions or concerns that it had before execution of the plan begins. [2 TR 74.]

Staff proposes the following modifications:

- 2) The Company should submit the IRM Investment Plan no later than four months prior to the start of each IRM Plan Year, not two months.
- 3) The Company should submit a copy of this plan to all intervening parties in the Company's most recently filed rate case, not just to Staff.
- 4) The Company should schedule and provide a forum for Staff and the intervening parties to raise any questions or concerns that they have before execution of the plan begins. This forum should occur no later than two months before the start of the IRM Plan Year.

## **IX. Staff's Other Issues**

### **A. Ford MIGreenPower (MIPG) Contract**

The Company requests that the Commission not treat the Ford MIPG contract as a special contract per Michigan Administrative Code R 460.2031 (Rule 31). (5 TR 2197.) The Company supports this request by describing the Ford MIPG contract as largely the same as service offered under the Company's existing Rider 17. The only differences between the Ford MIPG contract and Rider 17 noted by the

Company are the contract term (35 years for Ford MIPG versus as little as 5 years for Rider 17), contract termination, and contract termination fees. (5 TR 2194-2195.) The Company also argues that historically the special contracts subject to extra scrutiny per Case U-10646 were those that offered discounts to certain customers thus further review by the Commission was necessary to ensure that those discounts were in the best interest of all customers. (5 TR 2192-2193.)

Staff disagrees with the Company's framing of the Ford MIPG contract as substantially the same as Rider 17, and thus Staff also disagrees that the contract should not be treated as a special contract. (7 TR 4477.)

A special contract is one that is agreed to between the utility and customer to provide service not otherwise available in rates, rules, or regulations. Offering a discount is a sufficient but not necessary condition to defining a special contract and thus the additional scrutiny required. Deviation from existing, Commission-approved tariffs is the necessary condition. The fact that the Ford MIPG contract *is required at all* means that it is a special contract. The Commission recognized this fact already when it explicitly deemed the Ford MIPG a special contract in its December 21, 2022, order in Case U-21285. (7 TR 4477-4478.) For this reason, the Commission's requirement as set forth in Case U-10464 should also apply to the Ford MIPG special contract. (7 TR 4478-4479.)

On rebuttal the Company explicitly admits that the Ford MIPG contract differs from Rider 17 by concluding that the contract and Rider 17 have "similar

terms.” (5 TR 2232.) Staff notes here that the words “similar” and “same” have different meanings.

Staff recommends that the Commission deny the Company’s request to not apply Michigan Administrative Code R 460.2031 or the Commission’s prior special contract concerns to the Ford MIPG contract. Staff does not take issue with the Company’s proposal to present the analysis of the Ford MIPG contract required by U-10464 or Rule 31 in the Company’s renewable energy plan reconciliation cases.

**B. The Commission and ALJ should encourage the Company to cease the sale of uncollectible accounts to third parties, and warn the Company that such sales, net of proceeds from same, will be removed from the calculation of uncollectible expense to be included in rates.**

Staff witness Revere proposed that the Commission encourage the Company to discontinue sales of uncollectible accounts to third parties for collection, as the benefits to other customers are much smaller than the hardships to those whose accounts are sold. (7 TR 4616-4617.) Additionally, such sales effectively result in the uncollectible amounts being recovered twice; once from other customers through the inclusion of the remainder of such accounts not offset by proceeds from selling them in the calculation of uncollectibles expense to be included in rates, and again from the customers whose accounts are sold (by the parties who purchased those accounts). *Id.*

Company witness, Evette G. Griffie, asserts that there is no potential for double recovery in rates when uncollectible accounts are sold. (5 TR 2107). Staff agrees. However, as discussed above, Staff never claimed there was a possibility of

double recovery *in rates*. The double recovery occurs as the amounts (negligibly offset by the proceeds from sales of the accounts) are recovered once through rates, and again by the party to whom the accounts are sold. Not only does the account holder of the uncollectible account still have the responsibility of paying, but the Company's other customers *still have the responsibility of paying the vast majority of the same amount*. Company witness Griffie also claims that "[o]n behalf of our rate payers, it is the Company's responsibility to attempt to recover uncollectibles through available collection processes including debt sales." 5 TR 2107. And therein lies the rub. The Company *does not actually recover the uncollectibles through such debt sales*. Instead, only an exceedingly small portion is recovered from the sale, and the vast majority is *still paid by the ratepayers the Company is claiming to protect*, while subjecting what are likely among the Company's most vulnerable customers to the hardship-inducing collection tactics of the parties the debt is sold to, again resulting in potential double recovery (though not by the Company alone). (Revere, 7 TR 4616-4617.)

To prevent such issues, Staff recommends the Commission "encourage the Company to discontinue such sales, as the benefit to other customers does not outweigh the hardship imposed on those whose accounts are sold." (Revere 7 TR 4617.) In addition, Staff recommends the Commission put the Company on notice that if the Company continues such debt sales, "the remaining balance of the accounts not offset by proceeds from the sale will be removed from the calculation of uncollectible expense to ensure no double-recovery (once from the accountholders

and once from other customers) can occur.” *Id.* The Commission should also require that the Company file, for the previous 5-years, the number of accounts sold, the proceeds from the sales, and the amount of uncollectibles associated with the sold accounts so the information is available to calculate the adjustment to uncollectibles expense. *Id.*

**C. The ALJ should recommend, and the Commission should order, that the cost of the Company’s EV programs be allocated based on revenues by class.**

Staff witness Revere proposed a change to the method used to allocate the cost of the Company’s EV programs and pilots from distribution plant to revenue requirement split between production and distribution. (7 TR 4618.) Staff’s proposed method better reflects that the main benefit of the programs is downward rate pressure, and that these benefits are somewhat offset by increased allocation of costs based on the increased usage in the class the EV usage occurs within. *Id.* This downward rate pressure occurs through spreading costs allocated to all classes that do not vary with usage over greater usage, thereby lowering the cost associated with any given unit of usage for all classes in proportion to their part of the total. *Id.* Therefore, Staff proposed the most appropriate allocation that reflects the costs and benefits is allocating on overall revenue requirement split between distribution and power supply proportionally. *Id.*

Company witness, Habeeb J. Maroun, proposes that, to avoid a circularity problem in the COS, present revenues be used rather than proposed revenues/proposed revenue requirement. (5 TR 3157.) Staff agrees to this

modification, as it still achieves the same reflection of benefits and costs Staff's proposal was intended to capture while avoiding a circularity issue in the calculation of the allocation.

For these reasons, the ALJ should recommend, and the Commission approve, splitting EV program costs between distribution and power supply and allocating to the classes based on present revenue.

**D. The Commission should order certain deprecated language regarding resale and EV charging be removed from the Company's tariffs.**

Staff witness Revere recommending removing the following language from the Company's tariff book, Rider 4, resale of service, Sheet No. D-76.00: "For purposes of this tariff, the provision of electric 6 vehicle charging service for which there is no direct per kWh charge shall not be 7 considered resale of service." (7 TR 4619.) This proposal was made as the referenced language is a holdover from a previous change to the Company's tariffs relating to EVs that has been superseded by language added in the Company's previous rate case, so the removal of the superseded language would avoid confusion about how EV charging stations are allowed to charge for their services. *Id.* For these reasons, the proposed removal of the outdated language should be approved.

**E. Certain of MNSC witness Jester's claims and proposals related to rate comparisons should be rejected.**

MNSC witness Jester claims that, as most of an industrial customer's rates consist of power supply, the difference between the average industrial rate and the

average residential rate is a reasonable proxy for overall distribution rates and that industrial rates are a good proxy for power supply rates. (6 TR 3442.) This is incorrect:

The average power supply rate would be total power supply costs divided by total kWh. The allocation (as well as determinant and rate design differences) effects between rate classes could make a given class' average power supply rate higher or lower than the average. The claim is unsupported, and therefore the assumption that industrial rates are a good proxy for overall power supply rates should be rejected. [Revere 7 TR 4622-4623.]

Similarly, any other statements or claims made by the witness relying on this incorrect proxy should be rejected.

**F. Claims that EV programs should return the full value of gross margin from incremental load should be rejected.**

MNSC witness Jester claims the full value of gross margin from incremental load is applied to offset connections under line extension policies. (6 TR 3469.) This is incorrect. Line extension policies generally only apply 2-3 years' worth of expected revenue, sometimes offset by incremental powers supply costs, as an offset to line extension costs, including DTE's. (Revere 7 TR 4623.) Additionally, costs not covered by the customer installing a charger are necessarily borne by other customers and should therefore be considered a cost when determining net benefits of the program. *Id.* For these reasons, any arguments relying on this claim, including that “[c]onsidering marginal revenues from EVs on a service territory and system-wide basis appears to be the most natural basis for determining the gross

margin that can be used to fund transportation electrification programs” should be rejected.

MNSC witness, Jester, makes several other claims about how the full gross margin from all electric vehicle charging should be used to subsidize EV charger installation and other EV programs. (6 TR 3469-3474.) These claims ignore the goal of these ratepayer-funded programs, which should be to “should be to maximize the net benefit to all ratepayers as ratepayers. Eliminating or reducing the net benefit by allowing it to accrue to the benefit of EV owners alone is not supportive of this goal; it is, in fact, antagonistic to it.” (Revere 7 TR 4624.) No reasonable support was provided for the proposed subsidization of EV owners by other ratepayers in pursuit of the climate goals of the state. *Id.* By relying on the revenues from all charging alone for the proposals, MNSC witness Jester also fails to include a number of costs associated with the programs, which results in a net benefit calculation that is not. *Id.* For this reason, these proposals should be rejected.

Michigan Energy Innovation Business Council (MEIBC), Institute for Energy Innovation (IEI), and Advanced Energy United (AEU, collectively MEIBC/IEI/AEU) witness, Laura S. Sherman, makes similar proposals<sup>13</sup> that should also be rejected, as they are flawed in the same manner.

MEIBC/IEI/AEU witness, Sherman, frames not using full revenues from EV charging to enable the subsidization of such programs by other ratepayers as a

---

<sup>13</sup> 6 TR 4162, 4172, 4174.

“transfer of wealth from EV drivers to non-EV customers” and DTE shareholders. (6 TR 4172.) As no support is provided for this bold claim, it should be rejected as unfounded. (Revere 7 TR 4625.)

MNSC witness Jester claims the CBA used in support of their EV programs is flawed, as it attempts to discern the portion of EV revenue associated with the Company’s programs the CBA is in support of. (6 TR 3470.) Staff disagrees that this is a flaw, and considers it an appropriate feature, as “[a]scribing benefits to usage that would have occurred absent the program is inappropriate,” and would not properly reflect the benefits the costs of the program enable. (Revere 7 TR 4625.) For this reason, the claim (as well as the similar claim by MEIBC/IEI/AEU witness Sherman<sup>14</sup>) should be rejected.

**G. Ratepayers should not be responsible for all charging infrastructure.**

MNSC witness Jester claims that the Company’s Transportation Electrification Plan (TEP) should effectively fund all charging infrastructure discussed in the MI Healthy Climate Plan. (6 TR 3472.) Staff disagrees. The Company and its ratepayers should not be responsible for funding the infrastructure necessary to serve all EVs. (Revere 7 TR 4626.) Staff’s support for ratepayer funding extends only to those programs and investments that maximize ratepayer benefit by reducing barriers to entry and range anxiety; DCFC rebates, for example, are not to install all the chargers there is demand for, but to enable the

---

<sup>14</sup> 6 TR 4171-4172.

benefits to ratepayers of the pilots and programs by reducing range anxiety, as the benefit to ratepayers is effectively only off-peak at-home charging that would not have otherwise occurred. *Id.* For this reason, the proposal (as well as the similar proposal by MEIBC/IEI/AEU witness Sherman<sup>15</sup>) should be rejected.

**H. MNSC witness Jester’s unclear proposal regarding “revenues in excess of cost of service” should be rejected.**

MNSC witness Jester makes a nebulous and unclear proposal regarding rate design, claiming “any revenues in excess of cost of service should be addressed through rate reforms that bring revenues from this and other end-uses closer to cost of service.” (6 TR 3472.) The proposal is unclear at best, but insofar as special rates based on end uses may be being proposed, “it would first have to be shown that such end-uses differ substantially enough from the service provided to other customers on the otherwise applicable rates so as to justify a separate service class, and/or that the otherwise applicable rates fail to reflect the cost to serve in some way.” (Revere 7 TR 4627.) As MNSC witness Jester made no such showing, the proposal (as well as the similar proposal by MEIBC/IEI/AEU witness Sherman<sup>16</sup>) should be rejected.

---

<sup>15</sup> 6 TR 4174.

<sup>16</sup> 6 TR 4174.

**I. Charging delivery charges for delivery of energy is not a double charge.**

MEIBC/IEI/AEU witness Sherman makes the claim that it would be “a double charge for delivery to charge the full retail rate for electricity used to charge the vehicle or battery, credit the outflow from that battery or vehicle for only production and transmission costs, and then charge the full retail rate to the customers who subsequently use that same outflowed electricity.” (6 TR 4157.)

As the Company’s delivery system is used for delivering energy both to and from the battery, the delivery system used to do so must be paid for by the receiving customer in both cases; therefore, there is no double-charge, and the claim should be rejected. (Revere 7 TR 4627.)

**J. The technical requirements for EV chargers proposed by MEIBC/IEI/AEU witness Sherman should be rejected.**

MEIBC/IEI/AEU witness Sherman proposes “simple technical requirements” (testing laboratory certification, ENERGY STAR certified, and networked) for chargers under the Home Charger Installation program and Community Chargers pilot. (6 TR 4158, 4170.) As MEIBC/IEI/AEU witness Sherman provides no support for the necessity nor appropriateness of these requirements, they should be rejected; the networked requirement in particular is inappropriate given that many cars themselves are networked, negating the need for a networked charger. (Revere 7 TR 4628.) The proposed technical requirements should be rejected for these reasons.

**K. Additional incentives for bidirectional chargers should be rejected at this time.**

Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists and Vote Solar (collectively CEO) witness Margarita Parra proposes that bidirectional chargers receive additional incentives. (6 TR 3950-3951.) As CEO witness Parra does not show how such chargers provide additional benefit to the ratepayers funding the program, only to those receiving the incentive, the proposal should be rejected as unsupported. (Revere 7 TR 4628.)

**L. CEO witness Parra's proposal related to Rider 21 should be rejected as unsupported.**

CEO witness Parra makes a recommendation that “the Company assess the revenues that the electric school buses procured with the eFleet Battery Support can provide and include this in the savings potential for the Rider 22 tariff application.” (6 TR 3951.) It is not clear what this recommendation even is, so it should be rejected until properly explained and supported. (Revere 7 TR 4628.)

**M. Certain of EM witness Zakem's proposals and claims related to the State Reliability Mechanism (SRM) and associated capacity charge/rates should be rejected.**

Energy Michigan (EM) witness Alex J. Zakem claims that the State Reliability Mechanism (SRM) should be applied by taking the Capacity Charge in MW/day the Commission approves, multiplying that by the peak load contribution (PLC) of the customers the load-serving entity (LSE) identifies the charge should be applied to, and then charging the result of those calculations to those customers. (6

TR 4090.) Staff disagrees. The Commission determined in U-18239 that the capacity revenue requirement should be allocated to the classes on the 4 CP allocator, and then the result used to calculate a capacity rate for each rate schedule, which should then be charged to power supply capacity billing determinants in proportion to the amount the Company covers. (Revere 7 TR 4630-4631.) The Commission's determination in U-18239 was that the capacity charge in the context of the application to AESs (as the electric providers under the statute) must be the capacity rates under the tariff as currently calculated. (Revere 7 TR 4631.) As EM witness Zakem's proposed change is inconsistent with the statute and the Commission's interpretation thereof, it must be rejected. *Id.*

**N. Association of Businesses Advocating Tariff Equity (ABATE) witness James R. Dauphinais' refund method for the proposed Earnings Sharing Refund Mechanism (ESRM) should be modified if approved.**

ABATE witness Dauphinais proposed a refund associated with the ESRM that would distribute any refund to the classes under the mechanism to classes in proportion to the percentage of the final revenue requirement used to calculate their rates. (4 TR 1070.) While not taking a position on the ESRM itself, Staff opposes the proposed refund method, proposing the following as an alternative:

The total amount to be refunded would be split into two amounts based on the relative proportion of: (a) the amount by which the Company's actual revenue requirement (calculated in the same manner as that used in setting rates with any revenue not attributed to collection from rates treated as a reduction to the revenue requirement) was lower than that assumed in setting rates, and (b) the amount by which collected revenues from rates for each class exceeded projected revenues from rates used in setting rates

(excluding any amounts for classes for which revenues were lower than projected).

For example, if the amount to be refunded was \$9 million dollars, and the Company's actual revenue requirement over the period was \$15 million lower than that used to set rates and one class' actual rate revenues exceeded projected by \$10 million, another class' actual rate revenues exceeded projected by \$20 million, and the remaining classes' revenues were below projected by \$1 million each, the \$9 million would be split into \$3 million ( $\$9M * (\$15M / (\$15M + \$10M + \$20M))$ ) associated with the difference in expense and \$6 million associated with revenues ( $\$9M * ((\$10M + \$20M / (\$15M + 10 \$10M + \$20M))$ ). This portion is also similar to the method that was used for refunds under the former self-implementation refund process approved by the Commission.

The amount associated with expense would be allocated to the classes based on proportion of total projected revenue used to set rates (similar to the method proposed by ABATE initially), and the amount associated with revenues would be allocated to the classes for whom rate revenues were higher than projected (and not classes for whom rate revenues were lower than projected) in proportion to the amount of that class's overage to the total (similar to the method proposed by Staff initially. In the example given previously, the first class would be allocated \$2 million ( $\$6M * (\$10M / (\$10M + \$20M))$ ) and the second \$4 million ( $\$6M * (\$10M / (\$10M + \$20M))$ ), and the remaining classes none of this amount.

If no class had actual rate revenues above projected, no amount would be allocated on the basis of that difference; any amount to be refunded would then be treated as a difference in expense and allocated on that basis.

Any details that were missed or unforeseen in this explanation could be determined as a result of the order in the first contested case determining the refund under the mechanism; parties would be able to put forward arguments identifying any such issues and proposed solutions for the Commission to consider. [7 TR 4632-4634.]

This is the method recognized by ABATE witness Dauphinais as the reasonable alternative proposed by Staff in MPSC Case No. U-20836. As this method matches the refund to the cause better than the method initially proposed by ABATE, it is the method of refund that should be approved if the Commission approves the ESRM. (4 TR 1070-1071, 7 TR 4632-4634.)

**O. Souldarity and We Want Green, Too (collectively, the Detroit Area Advocacy Organizations or DAAO) witness Jackson Koeppl's claim that the value of distributed generation (DG) is not captured by the current outflow credit should be rejected.**

DAAO witness Koeppl claims that “[t]he current outflow credit does not represent the true present value of distributed generation” and that the credit should therefore be increased. (6 TR 4046.) Staff disagrees. DAAO witness Koeppl asserts that DG lowers energy costs but offers no evidence in support. (Revere, 7 TR 4634.) DAAO witness Koeppl also appears to claim that avoided health and climate impacts should be included in DG compensation, again offering no evidence or argument in support of the appropriateness of such. *Id.* As stated by Staff witness Revere, “providing such benefits as compensation would be economically equivalent to the benefits no longer existing for others, and the claim should therefore be rejected.” (7 TR 4634-4635.) DAAO witness Koeppl also appears to claim that the outflow credit should compensate for avoided losses and currently does not. (Revere 7 TR 4635.) As stated by Staff witness Revere, “[a]s the retail rate on which the outflow credit is based includes the cost impacts of losses, a further recognition would amount to a double-count.” *Id.* For the reasons listed above, DAAO witness Koeppl’s recommendation that the Commission order an evaluation of these claimed benefits<sup>17</sup> should be rejected.

---

<sup>17</sup> 6 TR 4047.

**P. DAAO witness Koepfel’s proposal for low-to-moderate income (LMI) customer DG incentives should be rejected.**

DAAO witness Koepfel proposes a higher outflow rate as well as direct incentives for LMI DG. (6 TR 4048.) No support is provided for these proposals, and they should therefore be rejected. (Revere 7 TR 4635.) In addition, DAAO witness Koepfel “mischaracterizes the support for such a proposal, as well as Staff’s response to same, in another case,”<sup>18</sup> and as stated by Staff witness Revere: “The modelling used to support the incentive in that case was fatally flawed as it did not take all costs of DG as a source of supply into account. Therefore, DAAO witness Koepfel’s mischaracterization should not be considered to support the requested relief.” (7 TR 4635.)

**Q. DAAO witness Koepfel’s proposal that ratepayers fund the purchase of batteries for LMI customers should be rejected.**

DAAO witness Koepfel proposes that ratepayers fund the purchase of batteries for LMI customers. (6 TR 4054-4055.) As no evidence is presented supporting the proposal, or showing the benefits to ratepayers would outweigh the costs, the proposal should be rejected. (Revere 7 TR 4636.)

**R. To the extent the Commission or ALJ considers the incorporation by reference of extensive testimony and exhibits from the records of other cases by DAAO witness Koepfel, the responsive testimony and exhibits to same should also be considered.**

Staff is concerned by the attempts by DAAO witness Koepfel to incorporate extensive portions of other case records into this case by reference or exhibit; as

---

<sup>18</sup> 6 TR 4049.

stated by Staff witness Revere, “[t]o the extent those incorporations are recognized by the Commission, any response to those testimonies from their respective cases should also be recognized.” (7 TR 4636.)

**S. Certain claims and proposals made regarding standby rates by Bloom witnesses should be rejected.**

Bloom Energy Corporation (Bloom) witness Peter Morse claims there are distribution benefits of Bloom systems<sup>19</sup>, but fails to quantify those benefits, or even present argument on why other customers should bear costs normally borne by standby customers under current rates; the claimed benefits should therefore not be considered by the Commission. (Revere 7 TR 4636.)

Bloom witness Morse claims that current standby rates are “extremely high”, fail to follow cost-causation principles, and are for a service unneeded by fuel cell customers. (6 TR 4111-4112.) Staff disagrees:

If the service were unneeded, the customer could disconnect the load served by such a system from the grid entirely and pay nothing to the utility. If not disconnected, the utility has to have the equipment in place to be able to serve the demand imposed on the distribution system by the customer. It is important to note that the current standby rates represent a discount from standard power supply rates to recognize the unique nature of service to standby customers, including the diversity amongst those customers and how that lowers the generation required to serve them. On the distribution side, however, the charges are the same as for a regular customer. This appropriately recognizes the fact that, at primary voltage levels, the current rate design structure is entirely based on demand. Revere 7 TR 4136-4137.

For these reasons, the claims should be rejected. Bloom witness, Douglas B. Jester, claims that the current standby rate assumes all customers will have

---

<sup>19</sup> 6 TR 4109-4110.

simultaneous outages as the distribution charges are not prorated. (6 TR 4123.) This is incorrect. The rate recognizes the difference between power supply and distribution cost causative factors, allocation, and rate design methods; prorating the distribution charges as proposed would fail to recognize these important differences and should be rejected. (Revere 7 TR 4637.)

Bloom witness Jester claims that outages of Bloom systems not configured for off-grid operation that occur as a result of the Company's grid conditions should not count as outages under the standby rate. (6 TR 4126.) Staff disagrees. Based on the information provided in the instant case, including by Bloom witness Morse,<sup>20</sup> there appears to be a way for Bloom customers to avoid such outages; as the customer is making that choice, other customers should not bear the cost of it. (Revere 7 TR 4637-4638.) Therefore, the claim and all claims and proposals related to distinguishing outages in such a manner should be rejected. Bloom witness Jester proposes contract capacity under the standby rate be calculated differently for modular systems with availability above 90%. (6 TR 4132.) Not only is the 90% threshold unsupported, failing to recognize the possibility that such a system could go down completely in how demand charges are applied would fail to reflect how costs are currently allocated and how rates are currently designed, making the proposal inappropriate. (Revere 7 TR 4638.) Therefore, the proposal should be rejected.

---

<sup>20</sup> 6 TR 4103.

Bloom witness Jester proposes standby distribution charges be based on incremental cost of transformer capacity for the customer at their connected voltage level. (6 TR 4133.) As the proposal was not properly supported by argument or evidence, it should be rejected. (Revere 7 TR 4638.)

Bloom witness Jester claims that the Rider 18 standby contract capacity for a Bloom system customer would be calculated by method (a) in the Company's tariff, and that all currently available methods of determining the contract capacity including this method "ignore the customer's choice as to the level of contract capacity desired and instead assume a worst-case scenario." (6 TR 4135-4136.) Staff disagrees. Bloom witness Jester provides no support for the claim that method (a) would be applied to a Bloom customer, nor why such application would not be appropriate. (Revere 7 TR 4639.) A customer's choice of the amount of standby service they desire is also irrelevant; the determining factor is the standby capacity they *require*, which is what all the methods of determining the necessary contract standby capacity are intended to accomplish, not the worst-case scenario claimed by Bloom witness Jester. (Revere 7 TR, 4639.) For these reasons, the proposals and claims should be rejected.

Bloom witness Jester claims that a customer with a Bloom system would have their Rider 18 3 standby contract capacity calculated by method (a) in the Company's tariff, and that 19 this and other currently available methods of determining the contract capacity "ignore 20 the customer's choice as to the level of contract capacity desired and instead assume a worst-case scenario."

**T. Michigan Municipal Association for Utility Issues (MI-MAUI) witness Richard Bunch’s claim that uncollectible expense should not be allocated to streetlighting customers should be rejected.**

MI-MAUI witness Bunch claims streetlighting customers contribute a minimal amount to uncollectibles expense and should therefore be allocated none of the expense. (4 TR 926-927.) As stated by Staff witness Revere:

The reason for the change in uncollectibles in MPSC Case No. U-20836 referenced by MI-MAUI witness Bunch is that, as a general cost of business, uncollectibles should not be attributed to the classes in the manner suggested. As stated by the Commission: “[t]he Commission agrees with the Staff that allocation on a general basis, such as total revenue, is most appropriate and aligns best with ratemaking principles.” Because no customer is responsible for another’s bill, uncollectibles are a general cost of doing business, and the amount of previous uncollectibles within a class does not matter with regard to the appropriate allocation. (7 TR 4639, internal citations omitted.)

For this reason, the claim and related proposal should be rejected.

**U. Distribution Planning and Equity Related Issues**

- 1. To support future environmental justice and equity analyses, Staff recommends the Commission request the Energy Affordability and Accessibility Collaborative define vulnerable community based on MIEJScreen composite scores and require future environmental justice analyses provide information in gradations based on these composite scores.**

The Company provides environmental justice (EJ) testimony, adopting the State of Michigan’s definition of EJ, focused on “equitable treatment and meaningful involvement of all people.” (3 TR 400-401.) The Company defines vulnerable communities to be census tracts with a MiEJScreen composite score at or above the 80th percentile. (3 TR 402.) It provides all-weather SAIDI and SAIFI

maps by census tracts for the service territory and the Detroit area (3 TR 406-409), as well as for vulnerable communities. (3 TR 413-416.) The Company also provides tables with data regarding reliability programs (Conversion, 4.8kV Hardening, and Tree Trim) and their deployment in vulnerable census tracts (3 TR 418-419.)

From its EJ analysis, the Company formed two main conclusions:

- The 483 census tracts meeting its definition of vulnerable community “collectively have above average reliability performance in years 2020 through 2022, for SAIDI and SAIFI metrics excluding MEDs and All-Weather SAIFI” compared to the overall system. (3 TR 411.)
- The Company’s “investments are supporting vulnerable customers and communities . . . in southeast Michigan, including the City of Detroit.” (3 TR 417.)

In terms of future EJ work, the Company notes that it will continue to analyze reliability and investment data using the MiEJScreen tool, add EJ considerations into its Global Prioritization Model (GPM), and collaborate with the MSPC and stakeholders on potential IIJA grant opportunities. (3 TR 420.)

For testimony purposes, Staff adopts the Company’s definition of vulnerable communities and the implied definition of non-vulnerable communities as those with MiEJScreen scores below 80<sup>th</sup> percentile. (7 TR 4731-4732.) Though the area of vulnerable communities appears small in comparison to the overall Company service area, nearly a quarter of the Company’s customers reside in vulnerable communities, with 19-32% of the Company’s distribution lines and circuits serving these communities. (7 TR 4733.) Nearly 48% of the Company’s 4.8kV customers reside in vulnerable communities. (7 TR 4732.)

Staff found vulnerable community customers had longer outage durations than the overall DTE system, non-vulnerable community DTE customers, and average U.S. customers from 2020-2022 (higher all-weather Customer Average Interruption Duration Index (CAIDI)). (7 TR 4736-4737.) Staff examined several areas when exploring why DTE vulnerable community customers have better SAIFI and SAIDI, but worse CAIDI than the system average and non-vulnerable communities. (7 TR 4738.)

First, in order to better understand the relationship between electric reliability and EJ, Staff recommends in direct testimony that future EJ analyses provide similar information, such as the summary tables the Company presented on reliability performance comparing vulnerable communities to the overall system and Company distribution investments for vulnerable communities, for the least vulnerable community customers. For example, if visual displays or data are provided for MiEJScreen Scores of 80-100%, the same could be provided for those with scores of 0-20%. Understanding and contrasting the experiences of the least vulnerable and most vulnerable communities may be similarly insightful. (7 TR 4733.)

Second, Staff, in direct testimony, recommends the Commission request Staff explore and recommend a threshold for vulnerable communities or community vulnerability gradations based on the MiEJScreen Score to be used in environmental justice analyses in future MPSC proceedings for Commission consideration and possible adoption. Though the Company adopts an 80-100% of

the MiEJScreen Score definition for vulnerable communities, Staff is unsure if this is the correct definition to use. Selecting a well-supported threshold or community vulnerability gradation will support usefulness of future environmental justice analyses. (7 TR 4734.)

Several intervenors filed testimony related to the Company's EJ testimony and Distribution Grid Plan (DGP). The testimony of Paul J. Alvarez on behalf of the Attorney General, Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan discusses financial, policy, and regulatory issues presented by the Company's DGP. Witness Alvarez recommends a new process for the next round of distribution plans in Michigan to ensure stakeholder participation throughout the process, to restore capital spending governance, and to mitigate information asymmetry. (6 TR 3342-3343.) He recommends:

- the Commission order risk-informed benefit-cost analyses be completed on any distribution investment plan project or program with capital spending exceeding \$100,000, and to include those analyses in plan workpapers. (6 TR 3353);
- the Commission order that risk-informed decision support be used to select the projects and programs for a distribution investment plan from a portfolio of potential investments. These workpapers, including documentation of the recommended risk tolerance level, and identifying the projects/programs deferred to a future plan as a result, should also be required to accompany distribution investment plans. (6 TR 3353);
- a proceeding where Staff, stakeholders, and utilities jointly create a process for developing five-year distribution investment plans. (6 TR 3343), where:

- The distribution plan process be created in a series of working groups led by Staff, based significantly on the Jade Cohort Roadmap established by NARUC-NASEO (6 TR 3343);
- the Commission stagger distribution plan development so no more than two plans are under development at the same time. (6 TR 3344).

If the recommendation for the above proceeding is not adopted, witness Alvarez recommends:

- Distribution plans be presented and evaluated in litigated proceedings specific to each utility. (6 TR 3371);
- There be no overlap between litigated distribution investment plan proceedings for different utilities. (6 TR 3357);
- Generous procedural schedules with sufficiently long discovery opportunities (6 TR 3338.)

Witness Dennis Stephens, testifying on behalf of the Michigan

Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan, and the Attorney General, notes that an improved distribution planning process will likely result in a much-improved distribution investment plan from DTE, one that better justifies implementation speed and geographic specificity while better balancing affordability with other distribution grid development objectives. (6 TR 3365-3366.) Witness Stephens finds “distribution planning as practiced in Michigan is inadequately governed and capital-biased, and leads to capital spending on unnecessary, unnecessarily early, and cost ineffective projects and programs.” (6 TR 3367.) In the development of current distribution plans, stakeholders did not have the opportunity to provide an informed counter to the utilities’ proposals and did not have procedural opportunity

to investigate and challenge the utilities' distribution investment plans. (6 TR 3368-3369.) Witness Stephens notes "considerable discretion exists as to what to install, where to install it, and when to install it" and that the complete and utter reliance on the utilities' claims is unadvisable. (6 TR 3369.)

Witness Stephens concurs with Witness Alvarez and recommends a distribution investment plan process that produces "a definition of what Michigan wants DTE's grid to be, and to be able to do, by when, with a means to measure progress and success (targets), and ideally, some processes and approaches to use when developing five-year distribution investment plans." (6 TR 3371-3372.)

Witness William D. Kenworthy, testifying for the Clean Energy Organizations, discusses distribution system planning and investment proposals made by the Company and their consideration and advancement of energy and environmental justice. He states, the Commission, in assessing what is "just and reasonable," must consider energy, environmental justice, and grid equity. (6 TR 3842.) He argues grid equity should be considered in rate cases as rate cases are where cost recovery is approved and distribution system plans are rigorously evaluated by the Commission. Grid equity cannot be only considered in reliability reporting and distribution system planning dockets. (6 TR 3843.)

Witness Kenworthy argues that though the "Company and the Commission acknowledge the importance of considering equity in grid modernization and distribution system planning, the DSPx framework [used by the Company in its distribution grid plan] does not provide adequate guidance for evaluating and

planning for an equitable grid.” (6 TR 3846.) Witness Kenworthy concludes that the Company failed to incorporate the findings of its environmental justice analyses into its decision-making process or investment decisions in this case. (6 TR 3849.)

Witness Kenworthy recommends that “equity considerations must be incorporated into the decision-making process [sic] that drive strategic capital investments, such as the Global Prioritization Model [GPM]” by:

- Amending the GPM to weigh reliability in EJ communities and adjust current budget and investment proposals in the instant case. (6 TR 3852);
- Requiring the “Company fully incorporate equity and environemtal [sic] justice into its decision-making process in the upcoming distribution plan . . .” (6 TR 3853); and
- Having the Company commit to adopting the revised GPM in its next rate case. (6 TR 3853).

Witness Kenworthy notes the importance of comparing reliability experiences of customers in similar communities, not just comparing system wide averages. (6 TR 3853.) He finds SAIDI is “notably worse in EJ communities” in Wayne County. Reliability is also uniformly better in Wayne County than the rest of DTE’s service territory, a difference likely explained by different physical grid topology and attributes. (6 TR 3855.) He recommends:

- The Company evaluate and strive to achieve equity across all dimensions of utility performance. (6 TR 3858);
- The Commission require a full and fair consideration of grid equity and energy justice before approving significant new investments. (6 TR 3858.)

Witness Kenworthy notes that if spending proposals in the instant case reflect a strategic shift from 4.8kV hardening to conversion, then accelerating the

equity analysis would help inform the Company's plans and near-term spending. (6 TR 3861.)

Witness Boratha Tan, testifying for the Clean Energy Organizations, discusses a regression analysis of DTE's reliability data by census tract. (6 TR 3921.) Witness Tan states that the Company's system level data "masks system characteristics when accounting for other characteristics of census tracts" and it could better compare reliability experiences of vulnerable community customers if it considered data, such as race and income, from census tract demographic measures. (6 TR 3925-3926.)

The regression analyses several demographic variables and claims that they are statistically significant predictors of reliability performance. Witness Tan concludes that "census tracts with more people in poverty experience longer outage durations" meaning "those least able to adapt to an outage are...most likely to experience the longest outages." (6 TR 3935.) According to CEO, area median income and black population percentage were statistically significant in all scenarios for CAIDI. (6 TR 3934.) However, Staff and the Company dispute the quality of CEO's analysis later in this brief.

Witness Tan finds that most census tracts within the Company's service territory are low-income communities with 80-100% of the population at or below the poverty line. Clustering of data is also seen for population density. As such, the regression analyses conducted could be further improved as this clustering of data can impact the analyses. Witness Tan notes that the regression results show the

complexity behind reliability metrics and the need to develop robust ways to analyze the Company's reliability data. (6 TR 3937.)

Witness Tan recommends the Company adopt regression analysis at the census tract level to better understand system reliability and energy equity in addition to utilizing the MiEJScreen tool. (6 TR 3937-3938.) Staff agrees with this recommendation despite its qualms with the actual analysis provided by CEO in the instant case.

Dr. Guillermo Pereira, testifying for CEO, analyzes and provides recommendations to improve the Company's environmental justice and equity analysis. (6 TR 3884.) Dr. Pereira recommends:

- The Company should consider vulnerable communities such as those on the 75<sup>th</sup> percentile of the MiEJScreen, in alignment with California's definition of disadvantaged communities. (6 TR 3896.) The Company should also provide its EJ analysis considering different thresholds, especially to consider how reliability affects exceptionally burdened communities and to identify and mitigate electric service inequities. (6 TR 3897);
- The Company should analyze sociodemographic factors, in addition to the composite MiEJScreen score, such as low-income households and communities of color. (6 TR 3898);
- The Company should present its findings comparing EJ to non-EJ communities to assess inequities, as comparing reliability in EJ communities to system averages may mask reliability discrepancies. (6 TR 3899);
- The Company should provide details on how its EJ analysis has affected and will affect investments;
- The Commission should expand its energy equity guidance and set goals and expectations on how such analyses must be conducted, reported, and integrated into Company decision making. (6 TR 3903);
- The Company should consider experience from other jurisdictions to propose an equity framework that is more encompassing and goes beyond reliability;

- The Commission and the Company should work together with stakeholders to formalize energy justice metrics and goals.

Witness Jackson Koeppel, testifying on behalf of Soulardarity and We Want Green, Too, collectively, Detroit Area Advocacy Organizations (DAAO), finds DTE's actions, incentives, and statements in the rate case indicate that its business objective is maximizing long-term shareholder profit. (6 TR 3976.) Witness Koeppel argues that the Company misuses the term "affordability" as a synonym for cost and that its ratepayer focus is about economic efficiency and not whether the Company's services are affordable. (6 TR 3976.) He emphasizes the importance of the Commission's role in protecting the welfare of ratepayers and aligning DTE's actions with the public interest. (6 TR 3976-3977.)

Witness Koeppel explains how the DAAO uses the Social Interest Principle (SIP) to inform a broader framework for a just energy transition. (6 TR 3977.) The SIP approach to energy system transformation accounts for "historic inequalities and then strategically, aggressively, and doggedly invest into their improvement." (6 TR 3978.) The DAAO believes energy inequity presents in three intersecting crises for frontline communities in the energy transition: affordability, infrastructure quality, and technology access. (6 TR 3979.) Witness Koeppel argues for solutions that holistically address all three crises. (6 TR 3981.)

Witness Koeppel believes the issues from DTE's "outdated, undermaintained, unreliable, and unsafe" electric distribution system is "more concentrated in communities served by the 4.8kV distribution systems and communities with lower incomes and higher concentrations of BIPOC people." (6 TR 4023.) He finds DTE's

data shows “vulnerable communities spend more time without power and wait significantly longer for power to be restored” and “a significant service disparity between vulnerable census tracts and the rest of the system.” (6 TR 4024, 4025.) Witness Koeppel also notes that the substantially older 4.8kV infrastructure is ungrounded, making it prone to life-threatening failures, and is “limited in its capacity to host distributed generation, community-based community solar, and smart grid technologies.” (6 TR 4026.)

Witness Koeppel describes the extensive documentation of the impacts from recent outage events this past winter, which he notes are “increasingly severe for residential ratepayers in communities with high cumulative impacts, who experience longer restoration times and are more statistically likely to have financial, language, and ability barriers to manage the disruption.” (6 TR 4027.)

Witness Koeppel testifies that the estimated economic impact of power outages in Oakland, Wayne, and Macomb counties exceeded \$485 million in 2020. (6 TR 4027.) He further testifies that though no such estimate for 2022 was made, all-weather SAIDI increased overall (352 to 582 minutes) and more than doubled (361 to 737 minutes) for vulnerable communities from 2020 to 2022, suggesting that the economic impacts from outages are “growing more severe overall and particularly for vulnerable communities.” (6 TR 4028.) Witness Koeppel estimates Highland Park, Michigan, experiences an estimated \$1 to \$2 million of economic damages annually or about 8-16% of the annual municipal budget. (6 TR 4028-4029.) He

also shares the human impact of outages, “especially for Highland Park’s senior and disabled populations, who face significant threats to life and health.” (6 TR 4029.)

Witness Koeppel believes there are existing race-class equity issues regarding grid quality and performance and that further analyses are needed to better understand the relationship between reliability, outage restoration, 4.8kV or 13.2kV system type, and recent maintenance or capital investments. (6 TR 4030.)

Witness Koeppel testifies that these race-class equity issues extend to the Company’s investment plans overall, where the “Company’s upgrade and improvement plans provide disproportionate benefits to privileged communities inside of Detroit that are experiencing an influx of white and high-income people, while leaving other neighborhoods like Highland Park and Hamtramck with basic maintenance.” (6 TR 4031.) “Customers in areas targeted by [City of Detroit Initiative] also experienced substantially lower average minutes without power than those areas targeted by hardening in 2021.” (6 TR 4031.)

Witness Koeppel argues that spending should reflect actual needs and lead to improved outcomes for ratepayers. This need, he argues, is greater for Detroit and vulnerable communities than the Company allocates to the areas currently. (6 TR 4033.) He believes DTE’s projections for the proportion of spending on conversion in vulnerable communities “primarily benefit areas experiencing demographic change due to gentrification or are designed to serve industrial load centers, rather than address service deficiencies for the actual vulnerable ratepayers.” (6 TR 4033.) In addition to increasing and reforming outage credits, he recommends the

Commission require the Company to improve integration of equity analysis into the Company's infrastructure investment prioritization. (6 TR 4039.)

Witness Koeppel finds the Company has not demonstrated that its infrastructure investment plan is equitable. The Company's own analysis shows significant racial and economic service disparity, which does not appear to significantly factor into the Company's investment decisions. The proposed Investment Recovery Mechanism also removes opportunities to improve equity analyses for a substantial amount of DTE's near-term distribution capital investment. (6 TR 4042.)

He recommends the Commission order DTE to conduct a rigorous and proper equity analysis prior to any further case filing, order DTE to conduct regression analyses as recommended by Witness Tan and update the GPM for achievement of improved racial and economic equity in grid performance. (6 TR 4041.)

Witness Jackson Koeppel rebuts Witness Paul Alvarez, arguing for key nuances to consider in adopting witness Alvarez's recommendations to ensure equity for all ratepayers in all communities rather than just general ratepayer interest. (6 TR 4062.) Witness Koeppel argues a "broader conceptual approach" in examining divergence of ratepayer and shareholder interest to include "the dynamic relationship among grid quality, affordability, and technology access." (6 TR 4064.)

Though witness Koeppel is supportive of witness Alvarez's recommendations for a more robust and risk-informed infrastructure planning process, witness Koeppel recommends that the risk analysis approach must be robust in its

measures and go beyond service interruption alone. (6 TR 4064-4065.) In addition, witness Koeppel recommends the risk analysis approach and stakeholder process address the disproportionate risks to different communities. He amends witness Alvarez’s algorithm to include a community risk vulnerability multiplier. (6 TR 4065-4066.) Witness Koeppel supports efforts to advance a more transparent process for infrastructure planning centered on ratepayer interests. (6 TR 4066.)

The Company rebuts Staff and intervenor testimony regarding environmental justice. The Company believes it should not be ordered to conduct the numerous and varied analysis undertaken by Staff and intervenors summarized in Rebuttal Table 1, claiming that such analyses “could skew results away from the most heavily impacted EJ communities.” (3 TR 429-430.) The Company, in rebuttal, claims that the “[a]dditional complex analysis as advocated by other parties distracts from the reliability improvements the Company is proposing in the instant case and EJ plan enhancements will be discussed in the 2023 DGP. . . .” (3 TR 441.)

Staff disagrees that the analyses it and intervenors provided in the instant case distracts from the Company’s proposed reliability investments in the instant case. Reviewing the environmental justice and equity implications of the Company’s proposals is important in evaluating the reasonableness and prudence of these investments. The Company, in rebuttal, admits that its environmental justice analyses is “simple and straight forward.” (3 TR 440.) As Staff and intervenors point out, the Company’s analysis, in its simplicity, misses important

environmental justice and equity findings and considerations. The Company's simplistic environmental justice analyses are not sufficient for evaluating the environmental justice and equity implications of its proposed investments, as well as the current and subsequent reliability impacts for different customer populations, especially vulnerable community customers.

The Company rebuts witness Pereira's claim that the use of averages in the Company's reliability analysis by census tract could mask discrepancies in the data. The Company claims that "data for customers not in the draft MiEJScreen tool 20% are readily calculated" from the system average and vulnerable community data it provided. It also notes it provided detailed maps in direct testimony and data in discovery by census tract allowing stakeholders to run different analyses and did not mask discrepancies. (3 TR 439.)

Though the Company did provide data in discovery by census tract, the Company's rebuttal of witness Pereira's direct testimony seems to miss witness Pereira's point that a focus on system-wide averages versus vulnerable community averages is simplistic. Other data analyses, especially factoring in detailed demographic information, could support an improved understanding of reliability, demographic data, and vulnerable community customer experiences. (6 TR 3927.)

The Company rebuts witness Tan's regression analysis, pointing out several concerns and issues with witness Tan's analysis. (3 TR 435-438.) Company witness Kryscynski recommends witness Tan's regression analysis not be given any weight in the instant case due to not being mathematically sound and disagrees with

witness Tan's recommendation that the Company adopt a linear regression analysis to process and interpret reliability data. (3 TR 438- 439.)

The Company rebuts witness Pereira and witness Dr. Wang's recommendations regarding a revision of the threshold definition of vulnerable communities. The Company claims "[c]hanging the threshold to the 75<sup>th</sup> percentile or creating gradients which in [sic] the EJ populations would distract from the Company's initial focus on the most vulnerable populations." (3 TR 440.)

In brief, Staff revises its original recommendation for the Commission to request Staff to recommend a threshold or gradations for defining vulnerable communities. Staff notes the Company's reluctance to move away from its current definition of vulnerable communities in its rebuttal of witnesses Pereira and Dr. Wang's separate recommendations to examine or review the vulnerable community definition. Staff also recognizes the Commission, in its November 18, 2022, order in MPSC Case No. U-20836, ordered the Energy Affordability and Accessibility Collaborative (EAAC) to "define equity and related terms as well as establish metrics for the energy infrastructure."<sup>21</sup> This work is ongoing. The EAAC may be engaged in defining vulnerable communities in its work. However, in case it has not yet, Staff revises its recommendation to recommend the Commission request the EAAC, in its work to define equity and related terms, to also define vulnerable community or environmental justice community based on a threshold of

---

<sup>21</sup> MPSC Case No. U-20836, 11/18/2022 order, p 463.

MiEJScreen composite scores for use in environmental justice analyses in future MPSC proceedings for Commission consideration and possible adoption.

Staff revises its recommendations in brief to combine aspects of the two following recommendations made in direct testimony:

- Staff recommends the Commission require future environmental justice analyses also provide similar information for least vulnerable community customers. (7 TR 4788.)
- Staff recommends the Commission request Staff to explore and recommend a threshold for vulnerable communities or community vulnerability gradations based on the MiEJScreen Score to be used in environmental justice analyses in future MPSC proceedings for Commission consideration and possible adoption. Understanding and selecting a well-supported threshold or community vulnerability gradations will support the usefulness of future environmental justice analyses. (7 TR 4788.)

Staff now recommends the Commission require future environmental justice analyses provide information in community vulnerability gradations based on the MiEJScreen composite score. Staff recommends the Commission request these gradations be defined initially as 0% to <5%, 5% to <10%, in 5% gradations up to 95%-100% of the MiEJScreen composite score, where the Commission may revise these gradations at its future discretion. This data meets the intent of Staff's first recommendation, as well as incorporates the recommendation for community vulnerability gradations from the second recommendation. Given the disparate recommendations regarding the definition of vulnerable communities, providing data in the recommended format will allow the utility and various stakeholders to have the data necessary for the analyses of interest to them. It also allows the utility, Staff, and stakeholders to more rapidly adopt the determined definition for

vulnerable communities once decided upon by the Commission and recommended by the EAAC, as the data will be available to do so.

Given this more detailed recommendation, Staff's first recommendation made in direct testimony is duplicative. If the ALJ and Commission do not adopt Staff's revised recommendation to require future environmental justice analyses to provide information in community vulnerability gradations based on the MiEJScreen composite score, then Staff recommends the Commission adopt the more general recommendation to require similar information be presented for the least vulnerable community customers as the most vulnerable community customers.

- 2. Staff revises its GIS data related recommendations in brief. Staff recommends the Commission require the Company, in future rate cases and distribution plans, provide data on interruption by zip code and census tract.**

The Staff believes there are likely disparities in the electric distribution systems serving vulnerable communities and 4.8kV system characteristics likely significantly contribute to the reliability differences. (7 TR 4738-4739.) A disproportionate number of vulnerable customers (73%) are served by the 4.8kV system, even though vulnerable customers represent only 24% of the Company's total customers. (7 TR 4739.) The City of Detroit, where much of the Company's vulnerable communities are located, is almost entirely served by 4.8kV, with 80% of that as rear-lot construction which present operations and maintenance difficulties. (7 TR 4740.)

4.8kV system characteristics, when compared to the 13.2kV system, may contribute to the better SAIFI and worse CAIDI for vulnerable communities compared to nonvulnerable communities. (7 TR 4741.) 4.8kV system customers generally experience fewer outages (lower SAIFI) but longer duration (higher SAIDI) than experienced by 13.2kV system customers. (7 TR 4742.) 4.8kV system characteristics may contribute to reliability challenges like increased outage durations that increase SAIDI and CAIDI. (*Id.*) These challenges include:

- older equipment;
- weaker strength conductors below current standards;
- largely overhead distribution lines (82% of 4.8kV is overhead compared to 57% of 13.2kV system that is overhead (7 TR 4744.)), where overhead equipment failures represent nearly 25% of all outage events (3 TR 528);
- fewer undergrounded residential lines (48% of 4.8kV system underground lines are underground residential distribution (URD) lines compared to 75% of 13.2kV underground lines that are URD lines (7 TR 4744));
- limited remote monitoring and control abilities; and
- ungrounded delta configuration makes maintenance, fault location, and detection of wire downs more difficult. (7 TR 4744-4745.)

Staff recommends the Commission require the Company, in future rate cases and distribution plans, to provide reliability performance by census tract as geographic information system (GIS) data layers in the form of shapefiles. Staff recommends the data layers include, but not necessarily be limited to, the following reliability metrics (7 TR 4745):

- SAIFI;
- SAIDI;

- CAIDI;
- Customers Experiencing Multiple Interruptions (CEMI) with 6 or more sustained interruptions per year; and
- Customers Experiencing Lengthy Interruption Duration (CELID) of  $\geq$  16, 48, and 96 hours of interruption in a year.

Having reliability data provided as GIS data layers will improve understanding of the geographic distribution of system reliability and equity, as well as an understanding of outage credit locations. It will also cost-effectively support a multitude of analyses without the Commission, Staff, and intervenors requesting each new map and analysis from the Company. (7 TR 4747.)

The Company rebuts Staff witness Dr. Wang's recommendation for the Commission to order the Company to provide GIS shape file data. The Company notes it does not have reliability data in the requested format. It also claims GIS shapefiles contain detailed circuit level and sensitive data and "should be protected from public access due to grid security considerations." (3 TR 445.) It further notes that the Commission has ordered the Company to provide the metrics Dr. Wang requests in MPSC Case No. U-21122 and that it is unreasonable and overly burdensome for the Company to maintain a second set of data in a new format. (3 TR 445.)

Staff disagrees with the Company's claim that GIS shapefiles universally contain sensitive and circuit level data that should be protected due to grid security concerns. It is possible to provide GIS data while still protecting customer information and grid security.

Though Staff's recommended metrics are included in some form in the U-21122 report, CEMI and Customers Experiencing Lengthy Interruption Duration (CELID) data are not reported at the census tract or zip code level. CEMI and CELID data are only reported at the overall system level. Staff acknowledges that providing the same data that was ordered in MPSC Case No. U-21122 in a new format may be burdensome.

Though the Company, in rebuttal, notes that it does not have reliability information in GIS shapefiles and has concerns that such information contains sensitive grid information, it now has experience and is now comfortable providing census tract and zip code data by month in MPSC Case No. U-21122. This spreadsheet data, when provided at the census tract or zip code level, can be uploaded into GIS software for analysis and avoids the sensitive grid information concerns that the Company believes accompanies GIS shapefiles. The Company, in rebuttal, also notes that Staff and other stakeholders can align publicly available census tract shapefiles with the metrics that the Company provides via spreadsheet in MPSC Case No. U-21122. (3 TR 445.) Staff agrees that spreadsheet data, when providing census tract and/or zip code level data, can similarly support the GIS analyses desired by Staff.

The Company's provision of tree trimming and reliability investment maps from 2018-2024 and circuits that have received 4.8kV hardening on maps in rebuttal further demonstrates the information asymmetry facing Staff and intervenors in the instant case, as well as all cases before the Commission.

(3 TR 434.) Though it was readily available to the Company for its use, Staff and intervenors did not have access to this geographic information from 2018 through 2024 until the Company provided it in rebuttal as images. The Company's rebuttal further highlights the need for it to provide greater data transparency and access to Staff and intervenors initially so that they can effectively review the Company's proposals in rate cases, distribution plans, and other Commission proceedings. The information asymmetry negatively impacts Staff and intervenor review and analyses, as the Company points out in rebuttal. (3 TR 432-434, 442.)

The Company's rebuttal also supports longer time horizons when evaluating historic program investments. It finds issue with Staff's review of reliability investments over a two-year time frame. Instead, the Company examines the investments starting from 2018, five years prior to the current year. (3 TR 432-434.) Staff agrees with the Company's rebuttal assertion that longer time frames must be used when evaluating infrastructure investments and upgrades and adopts the five-year time frame the Company uses in rebuttal. (3 TR 431.)

Staff revises its GIS data related recommendations in brief to the following:

- Staff recommends the Commission require the Company, in future rate cases and distribution plans, provide data on Customers Experiencing Multiple Interruptions (CEMI) with 6 or more sustained interruptions per year, and Customers Experiencing Lengthy Interruption Duration (CELID) of > 16, 48, and 96 hours of interruption by zip code and census tract, identified by census tract GeoID number with census version identified. This information is recommended to be provided by month for the historic period of the rate case or the two years prior to the rate case or distribution plan filing date, whichever is greater, in one or more spreadsheets.
- Second, Staff recommends the Commission order the Company to provide spreadsheet data in future rate cases and distribution plans that notes the

zip code and census tract locations that received and are projected to receive reliability related investments by program, including, but not limited to, tree trimming, 4.8kV Hardening, 4.8kV Conversions, Customer Excellence, PTMM, and CODI. Staff recommends the Commission require census tracts be identified by GeoID number and the census version noted. Staff further recommends this information be provided by program and by year for the five years prior to rate case or distribution plan filing year to adequately evaluate infrastructure investments and upgrades. Staff recommends that the information be provided by program and by year for all future years for which the Company provides projected investment spend.

**3. Staff recommends that known public safety hazards should be addressed according to adopted rules.**

**a. Statute and prior Commission orders require that the distribution system be maintained for the safety of the public.**

In its September 23, 2016, Order in Case No. U-18172, the Commission ordered the Company to investigate the circumstances causing the electrocution of a 12-year-old girl in Detroit on September 7, 2016, as authorized by MCL 460.556 to ensure that electric utilities in its jurisdiction maintain and operate the distribution system “for the security and accommodation of the public.” (7 TR 4749 (quoting MSPC Case No. U-18172, September 23, 2016, Order, p 2)). The Commission ordered “the utility to make the improvements that are necessary to ensure that such incidents are never repeated.” (7 TR 4749 (quoting MSPC Case No. U-18172, September 23, 2016, Order, p 3.)) The Commission found the investigation “revealed that the out-of-service arc wire presents a potential safety hazard to the residents of Detroit.” (7 TR 4749 (quoting MPSC Case No. U-18172, December 7, 2017, Order, p 7.)

The Staff finds that safety implications of the Company's 4.8kV system include:

- Typically live down wires since protective devices typically do not trip for about 80% of faults, including wire downs, (7 TR 4747, Staff Exhibit S-11.6, p. 15);
- Longer outage durations due to (7 TR 4747):
  - Ungrounded delta configuration that makes detection, location, and protection of single-phase downed wires challenging;
  - Ringed circuit and banked secondary designs that make fault identification, troubleshooting, and restoration more difficult (2 TR 198);
  - Limited remote monitoring and control capability (2 TR 198);
  - Presence and energization of abandoned Detroit Public Lighting arc wire co-located on about 50% of poles on an average Company circuit in the City of Detroit. (7 TR 4748; Staff Exhibit S-11.6, p. 21.)

Though the Company's measures of success in the 4.8kV Hardening program indirectly relate to security and accommodation of the public, they do not directly measure actual public safety or illuminate injuries and deaths from third party contacts. (7 TR 4749.) The Company does not collect data on the number of injuries and deaths from third party contacts on its system and is not required to collect such data. It is only required to retain records for injury and damages in cases where a settlement occurred. (7 TR 4749-4750.)

**b. Staff finds that arc wire could be removed at a faster pace, enhancing public safety.**

The Company developed the 4.8kV Hardening Program as a "near-term, cost-effective way to improve public safety, by removing arc wire and improving

reliability within the city of Detroit, and surrounding communities by addressing some of the oldest infrastructure in DTE's service territory as quickly as possible.” (Staff Exhibit S-11.10, p 1.) The company “determined that 4.8kV Hardening was the best option at the that time, as it was a timely and cost-effective method to remove arc wire.” (7 TR 4750 (quoting 3 TR 508).) There has been substantial variation in the miles of arc wire removed by the Company, with a ramp up in activity in 2022. In 2022, 42% to 43% of the total miles hardened and miles of arc wire removed, respectively, by the 4.8kV Hardening Program through 2022 occurred. (7 TR 4752.) Throughout the program, the miles of arc wires removed was far less than the total miles hardened per year, ranging from 35-57% of total miles hardened per year and averaging about 46.5%. (*Id.*) Though it is technically feasible to harden areas with only arc wire present, the Company elects to harden the entire circuit even if no arc wire is present in the circuit area. (7 TR 4753, Staff Exhibit S-11.10, p 5.)

The total amount of arc wire miles removed by the 4.8kV Hardening Program from 2017-2022 is low. The Company's arc wire removal pilots had higher arc wire removal rates. In Pilot 1, it removed 0.95 miles of arc wire in 12 days and 1.23 miles with heavy tree trim over 30 days. (7 TR 4754.) In Pilot 2, the Company removed 14.3 miles over three weeks and 11.3 miles over five weeks. In the 4.8kV Hardening Program from 2018-2021, the Company removed a monthly average of 4.4-10 miles of arc wire. In 2022, the Company removed an average of 18.7 miles per month, removing nearly as much arc wire in 2022 as it removed in all prior

years in the program. (7 TR 4774-4775.) The Company demonstrated through its pilots and 2022 performance that it has the capacity to remove much more arc wire than historically achieved prior to 2022. If it removed arc wire at the 2022 pace throughout the 4.8kV Hardening Program, the arc wire hazard in the City of Detroit would have been fully addressed and removed by the end of 2023. (7 TR 4755.)

The Staff does not find the Company's proposed pace of arc wire removal to be expeditious in addressing a known public safety hazard or to be in alignment with the Commission's September 23, 2016, Order in Case No. U-18172. (7 TR 4758.) The Company's current plan to remove arc wire through the 4.8kV Conversion program will leave large areas of Detroit to endure the public safety hazards of arc wire on Company distribution assets for over 14 years. (7 TR 4757.)

The Company's proposed timeline for removing arc wire does not meet the rules regarding reasonable care, prompt correction of recorded conditions, and defects that are reasonably expected to endanger life or property, or that lines and equipment that are permanently abandoned are removed or maintained in a safe condition detailed by the Technical Standards for Electric Service and the National Electric Safety Code guidelines. (7 TR 4759-60.)

The 4.8kV Hardening Program, as the Company has conceived and executed it, is not efficient in meeting the Commission's initial and current motivations to expeditiously address the public safety issues. (7 TR 4756.) The Commission in MPSC Case No. U-18172 ordered the utility to make improvements to ensure

incidents such as the electrocution of the 12-year-old girl never repeat.<sup>22</sup> In the Company's last rate case, Case No. U-20836, the Commission reiterated the importance of public safety in its decision to find arc wire removal reasonable and prudent. It further noted that out-of-service arc wire continues to be a potential safety hazard to Detroit residents and that only the future removal of arc wire will eliminate this safety threat.<sup>23</sup>

Regarding the 4.8kV Hardening Program, Witness Dennis Stephens, testifying on behalf of the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan, and the Attorney General, assumes most wire down events are associated with non-electrified DPLD wire, concluding "that a more cost-effective way to reduce wire down events would be to remove the DPLD wire, and not to take on the capital cost of hardening[,]" and that the program is "clever way of the company to capitalize tree trimming costs that should be treated as O&M expense." (6 TR 3396-3397.)

- c. Staff believes the 4.8kV system presents unique public safety hazards based on the historical injuries and fatalities reported to the Commission from 2013 to 2023.**

Equity concerns arise from the Company's extended timeline to remove arc wires, as the City of Detroit is the only areas with Detroit Public Lighting

---

<sup>22</sup> MPSC Case No. U-18172, September 23, 2016, Order, p 2.

<sup>23</sup> MPSC Case No. U-20836, November 18, 2022, Order, p 94.

Department arc wire in the Company's service territory and the city is the core location of the company's vulnerable communities. (7 TR 4761.) Disproportionate public safety issues impacting vulnerable community customers in the City of Detroit during long outages include the following:

- Detroit has Michigan's highest density of individuals relying on electricity dependent durable medical equipment. Given that it is also the core of the Company's vulnerable communities, these customers may also have less resources to find or install alternative power sources to ensure electric reliability for the DME on which they depend. (7 TR 4762-4763.)
- A significant percentage of Detroit's population is likely to suffer health consequences if an outage occurs during a severe heatwave. (7 TR 4763-4764.)

The 4.8kV system has greater public safety concerns, when examining historical injury and fatality data, in comparison to the rest of the Company's service territory. (7 TR 4766.) Electric utilities and cooperatives are required under Rule 804 of the Michigan Administrative Code to "promptly notify the commission of fatalities and serious injuries that are substantially related to the facilities or operations of the facilities." Mich Admin Code R 460.3804. In the MPSC Case No. U-20169 Staff Report, Staff reviewed five years of incidents reported by the Company from June 30, 2013, through June 30, 2018. In this period, the City of Detroit's 4.8kV system incidents resulted in 100% fatal injuries. This is higher than 83% fatality rate on the 4.8kV system outside of Detroit and 33% fatality rate on the rest of the system (mainly 8.3kV and 13.2kV). (Staff Exhibit S-11.14, p 6; 7 TR 4766-4767.) Staff compiled reported injuries and fatalities reported to the Commission by the Company from July 1, 2018, through June 1, 2023. City of

Detroit incidents continue to result in fatalities (80%) at a higher likelihood than the total system (47.6%) and the system excluding Detroit (37.5%). For incidents reported from 2018-2023, Detroit was the only location with multiple unique incidents.

The higher incidence of third-party contact and fatalities in the City of Detroit cannot be attributed to Detroit's higher population alone. An estimated 27% of the Company's customers reside in Detroit, while Detroit fatalities represented 53% of all fatalities from June 2013 to June 2018 and 50% of all fatalities from July 2018 to June 2023 reported to the MPSC under Rule 804.

In its May 17, 2018 order in Case No. U-20169, the Commission expressed concern that "parts of DTE Electric's distribution system are exhibiting an inability to routinely provide the level of safe and reliable service that is required by law," noting particular concern "with the operation of the 4.8kV system and the question of whether it presents unique hazards."<sup>24</sup> Staff believes the 4.8kV system presents unique public safety hazards based on the historical injuries and fatalities reported to the Commission from 2013 to 2023. The City of Detroit has significantly higher fatality rates than other areas. The City of Detroit also has a historically higher rate of third-party contact incidences than other locations within the DTE Electric service territory and the increased fatality rate in Detroit cannot be explained by the city's population size alone. (7 TR 4769-4770.)

---

<sup>24</sup> MPSC Case No. U-20169, May 17, 2018, Order, p 2.

**d. Staff recommends future Company reports of third-party contacts reported under Rule 804, include additional information to the third party's health status and contact description.**

Staff recommends future Company reports of third-party contacts reported under Rule 804, in addition to the third party's health status, also require all the following information be provided:

- Location of contact.
- Distribution system voltage (4.8kV, 8.3kV, 13.2kV, etc.).
- Whether it involved a wire down.
- Whether it involved DPLD arc wire or distribution wire.
- Whether it involved overhead or underground infrastructure.

(7 TR 4767.) By including the above data more consistently in future reports of third-party contacts, there will be consistent data provided that supports future analyses regarding arc wire and safety across different distribution system voltage types. (7 TR 4770.)

**e. Staff finds that Company investments do not equally support vulnerable communities and non-vulnerable communities.**

The Company states that “the Company’s investments are supporting vulnerable customers and communities . . . in southeast Michigan, including the City of Detroit,” where “[s]upporting...means investing in the electric distribution infrastructure to facilitate improved safety, reliability and, where conversion occurs, increased capacity.” (3 TR 417; Staff Exhibit S-11.16, p 1.) However, the Company objected to answering whether it believes it supports vulnerable and non-vulnerable

customers and communities equally in discovery. It said that “[t]he Company makes investments into the distribution grid to support all customers’ needs and including safety, reliability, and capacity.” (Staff Exhibit S-11.16, p 1; 7 TR 4770-4771.)

Staff does not believe the Company equally supports vulnerable communities and non-vulnerable communities. First, customers in vulnerable communities do not have the same experience with electric reliability, restoration times, and safety that customers have in non-vulnerable communities. Second, Company programs do not equally target vulnerable and non-vulnerable communities, as programs in Table 6 and 7 of Company witness Kryscynski’s direct testimony historically have not been and continue to be unequally deployed in vulnerable and non-vulnerable communities. (7 Tr 4771-4772.)

Though nearly 73% of the Company’s vulnerable community customers are served by the 4.8kV system (Staff Exhibit S-11.5, p 2), only 46% of the circuits converted in the 4.8kV Conversion program from 2018 to 2022 were in vulnerable communities. (3 TR 418; 7 TR 4472.) From 2023-2024, the Company expects the same percentage of circuits to be in vulnerable communities of the 4.8kV Conversion program. This suggests that the Company’s selection of circuits to convert disproportionately selects non-vulnerable community circuits during this period. At the same time, 75% and 86% of the total program investment was or is projected to be in vulnerable communities. It is unclear why vulnerable community

circuits would be substantially more expensive to convert or harden compared to other locations. (7 TR 4772.)

Equity concerns arise when viewing the geographic distribution of recently completed and future reliability investments. (7 TR 4773.) Staff overlaid the reliability program areas over the 1939 federal Homeowners Loan Corporation map of Detroit to see if historical redline persists in electric reliability investments. From the overlay, large areas of formerly graded Hazardous (red) and Dangerously Declining (yellow) did not and will not receive reliability improvements from November 2022 through May 2024. (7 TR 4776.) Many formerly redlined areas near downtown Detroit will not receive reliability investments from DTE Electric through May 2024. The Company does not detail how areas are selected to participate in various programs and why certain areas will receive no reliability improvement investments over the near term. (7 TR 4777.)

Company witness Kryscynski rebuts Staff witness Dr. Wang's analysis of the 1939 HOLC redlining map of the City of Detroit and the Company's reliability investments from November 2022 through May 2024. The Company finds two issues with Staff's analysis: (1) it did not include the 4.8kV conversion projects which were not shown on the Company's website map; and (2) the time horizon was too short to consider infrastructure upgrades. (3 TR 431.) The Company provides figures of tree trim locations and locations of conversion projects from 2018-2024. (3 TR 432-433.)

The Company misconstrues Staff's analysis as suggesting that the HOLC map should be used to identify vulnerable communities. Staff clearly notes in direct testimony that its analysis was conducted to see if historic redlining persists in current Company reliability investments. (7 TR 4774.) Even with the Company's updated tree trim and conversion locations, there are still regions of central Detroit which were likely previously redlined that are untouched by tree trimming and the four reliability programs it highlights in rebuttal. As such, areas of historically redlined communities likely did not receive tree trim and other reliability program investments even when examining the six-year period from 2018-2014.

- f. Staff recommends the Commission require the Company to provide greater transparency into why projects, programs, and deployment locations are selected in future rate cases.**

How the Company selects participation project locations or the projects themselves is not transparent. It uses the GPM to evaluate and rank different projects and program during the capital approval process. The relative weights of different GPM "impact dimensions are based on expert knowledge and judgment" based on institutional knowledge and collective assessments of risk exposure. (Staff Exhibit S-11.16, p 2-3.) Expert knowledge and judgement significantly impact the Company's selected projects and programs. (7 TR 4778.)

Though the Company indicates that its objectives are in alignment with the Commission's own, they are not always. (Staff Exhibit S-11.17, p 6.) Maximizing stockholder profits, as headlines like "DTE Energy cut operations to meet profits

months before power outages” suggest, are not among the Commission’s objectives. (7 TR 4778.)

The Company’s objectives in selecting and designing projects are not always in alignment with affected customers. It has not completed any research specific to vulnerable communities (Staff Exhibit S-11.18, p 1.) It also does not understand what “customer concerns” are. (Staff Exhibit S-11.18, p 2.) Without engaging affected customers and understanding their concerns and needs, the Company will be unable to truly meet customer electric distribution grid needs. (7 TR 4478-4479.)

Lack of transparency impacts the ability to remove biases in project and program selection that might disproportionately impact or exclude a customer group. Without transparency, it is difficult to understand why perceived biases, like many past redlined communities near downtown Detroit not receiving reliability improvement investments, are occurring. Without understanding why biases might arise, it will be difficult, if not impossible, to address them so that future distribution investments and subsequent service quality improvements are equitably deployed. Greater understanding of the biases that might be present in how the grid is maintained and evolved is necessary to create the right regulatory incentives and disincentives to better align the electric service experienced by the Company’s customers with Commission objectives. (7 TR 4779.)

The Company rebuts Staff witness Dr. Wang’s assessment that the Company’s investment decisions do not equally support vulnerable communities. It provides updated tables in rebuttal showing that it has directed a large share of

resources to vulnerable community circuits through the 4.8kV Hardening program. (3 TR 442.) This data provision further highlights the information asymmetry facing Staff and intervenors. This information, if provided at the outset of the rate case, would have supported analyses by Staff and intervenors, which are denied to them when the Company includes such data in rebuttal, a point too late in the rate case process to support review, analysis, and questioning of the provided data.

The Company claims that its “pattern of investment highlights that the Company’s GPM criteria has been effective at prioritizing investment in vulnerable communities.” (3 TR 442.) If vulnerable communities were supported equally to non-vulnerable communities by the Company’s investments, the injury and fatality rate from third party contacts with the Company’s distribution system should not vary depending on community vulnerability. However, the City of Detroit, which is at the core of the Company’s map of vulnerable communities, has a substantially higher fatality rate from distribution system contacts than elsewhere in the Company’s territory. (7 TR 4766-4768.) Given the stark differences in the fatality rate in the City of Detroit’s 4.8kV system and the overall 4.8kV system, both of which disproportionately serve vulnerable community customers, versus the rest of the Company’s distribution system, someone may question how the Company’s investment decisions equally support vulnerable communities. (7 TR 4739.) The outcomes of the Company’s investment, especially regarding customer reliability and safety experiences, matter more than the investment patterns or investment amounts, as the Company seems to suggest in rebuttal.

The Company rebuts witness Kenworthy, claiming that it is unreasonable and unrealistic for the Company to refresh the GPM and submit a new portfolio of projects based on the result during the rebuttal phase of the instant case. It also disagrees with witness Kenworthy's belief that the Company did not provide a full and fair consideration of grid equity and energy justice, as well as witness Kenworthy's suggestion that the Commission should withhold approval of new investments. (3 TR 443.)

The Company rebuts witness Koeppel's conclusion that the Company's investment proposals in the instant case may have differed if the Company had taken a more robust equity approach. (3 TR 443-444.) It also disagrees with witness Koeppel's conclusion that there are significant racial and economic service disparities. (3 TR 444.) The Company also rebuts witness Koeppel's statement that DTE's 4.8kV Hardening and CODI 4.8kV Conversion investment decisions lack race or income focus. It claims its investment in these programs in the City of Detroit "show the Company's consistent long-term investment in vulnerable communities." (3 TR 444-445.)

The Company rebuts witness Kenworthy's recommendation that the Company should evaluate whether hosting capacity impacts EJ communities and use the results to inform its next DGP. (3 TR 445-446.)

The Company rebuts Staff witness Dr. Wang in her assertion that the Company should provide greater transparency into why projects, programs, and deployment locations are selected. The Company believes it has been transparent

through sharing its GPM model and selection criteria, as well as testimony and exhibits on project and programs. (3 TR 446.) Staff disagrees. The Company's lack of transparency is supported on the record. The Company confirmed that expert knowledge and judgement determine the relative weights of different GPM impact dimensions. (Staff Exhibit S-11.16, p 2.) The Company also pulls projects or programs ahead when others get delayed, but this flexibility cannot be quantified (Staff Exhibit S-11.17, p 4-5; 7 TR 4777-4778.) Expert knowledge and judgement significantly impact why projects, programs, and deployment locations are selected (7 TR 4778.)

Staff recommends the Commission require the Company to provide greater transparency into why projects, programs, and deployment locations are selected, especially for projects like 4.8kV Conversion and 4.8kV Hardening that impact vulnerable communities, in future rate cases and distribution plans. This should include geographic maps of program deployment locations and timelines, like the 4.8kV Conversion deployment map on page 13 of Staff Exhibit S-11.10. (7 TR 4779-4780.)

- g. Staff recommends the Commission require the Company include climate resiliency planning in future distribution plans, including a climate vulnerability assessment with 50- and 100-year climate forecasts at a minimum and a climate resilience plan.**

DTE customers expressed concern regarding the safety and reliability of the Company's distribution network and electric service. Many public comments in various Commission dockets and meetings expressed concern about the poor

reliability provided by the Company; undue hardship to low-income, minority, and medically vulnerable customers during outages; the burden of rising electricity rates in the face of poor reliability; and other concerns. Customer comments have highlighted the compounded safety issues arising from power outages, which can cause cascading impacts on other key services, such as water and wastewater treatment, and inequitable impacts of poor reliability. (7 TR 4780-4781.)

Stakeholders expressed concerns regarding the current planning processes. Indirect comments arise from comments protesting the rising rates and poor reliability that dominate the comments in the instant case. How the utility plans for and implements distribution system infrastructure impacts the subsequent reliability experienced by customers. Direct comments regarding planning processes similarly pertain to reliability, changing weather, and the need for electric infrastructure. (7 TR 4782.)

Direct comments in the MPSC Case No. U-21122 docket pertained to the insufficiency of current planning process in addressing the needs of the future as well as concerns about relying on only historical weather data for planning future distribution system investments. (7 TR 4782-4783.) In particular, the Initiative on Climate Risk and Resilience Law (ICRRL), states “[b]ecause climate change is and will continue to alter weather patterns, basing utility planning solely on historic weather data increases the potential for electricity outages and other reliability issues, to the detriment of customers.” (Staff Exhibit S-11.18, p 3.) The ICCRL recommends utilities engage in climate resilience planning and adoption of a

50-year or longer view of climate forecasts and planning for climate change impacts over the expected useful life of assets. (7 TR 4784.)

Climate resilience planning is sensible considering the extensive reliability challenges the Company and other Michigan utilities experience. Distribution system investments made 50 to 100 years ago present current challenges that compromise electric service quality and safety of the Company's current customers. Reasonable and prudent decision making regarding the electric distribution investments must examine whether these investments serve utility customers for their full equipment life, which usually far exceed a 5- to 15-year time frame. It makes sense that future climate forecasts for 50 to 100 years in the future be considered when evaluating distribution system investments made today. (7 TR 4785.)

Staff recommends the Commission require the Company include climate resiliency planning in future distribution plans, including a climate vulnerability assessment with 50- and 100-year climate forecasts at a minimum and a climate resilience plan.

The Company rebuts Staff witness Dr. Wang's recommendation that the Company include climate resiliency planning in future distribution grid plans. It asserts that the "useful life of most distribution grid equipment is typically less than 50 years." (3 TR 446.) It finds Staff's proposed time horizon of 50 to 100 years to be too long to be useful and "redundant to its existing planning processes." (*Id.*) The Company also expresses concerns that the cost and complexity of developing

meaningful scenarios supported by stakeholders is unknown. The Company claims that capable and reputable third parties must be identified, work bid out, and funding provided to conduct climate modeling. (*Id.*)

Staff disagrees with the Company's rebuttal that climate resiliency planning in future distribution plans is redundant to existing planning processes. Climate resiliency planning, as the ICRRL recommends, is a two-step process that involves a climate vulnerability assessment and a climate resilience plan. The climate vulnerability assessment first identifies "where and under what conditions assets and systems are at risk from impacts of climate change." (Staff Exhibit S-11.18, p 5.) The climate resilience plan "evaluates measures to reduce risk the risk to vulnerable assets and systems." (*Id.*) Though the Company may model a storm scenario that incorporates climate change impacts, Staff has not seen a discussion akin to a climate vulnerability assessment and climate resilience plan. (3 TR 446.) Given the increasing severity of storms and the subsequent reliability challenges, Staff finds it imperative that climate resiliency planning is considered when evaluating and planning distribution system investments.

Staff also disagrees with the Company's climate modeling concerns regarding stakeholder support, identifying third parties to conduct such models, the bid process, and the funding to conduct climate modeling. If the Company were to develop climate models from scratch, the concerns it identified should be considered. However, there is data publicly available for accepted climate models that the Company can utilize for climate resiliency planning.

Staff recommends the Commission require the Company include climate resiliency planning in future distribution plans, including a climate vulnerability assessment with 50- and 100-year climate forecasts at a minimum and a climate resilience plan.

- h. Staff recommends the Commission require the Company to develop a clear and repeatable process that allows interested parties to request, safely obtain, and use GIS data with different levels of detail for their own analyses.**

Staff has concerns regarding data access due to significant information asymmetry regarding the Company's distribution system and investments. It is difficult to understand planning implications if the Company does not provide data access. (7 TR 4788.) Lack of data access impacted Staff's analysis in the instant case, where the Company refused to provide GIS shapefiles for areas outlines in its online DTE Electric Reliability Improvements Map. Instead of creating a more accurate overlay with prior red-line areas, Staff could only use more inaccurate overlays in Word by playing with photo transparency. (7 TR 4789.)

Staff did not find the Company concerns in refusing data access legitimate (7 TR 4786.) The Company, in its extensive list justifying its refusal to provide GIS data, claimed disclosure of the information would cause the Company and its customers hardship and that it included critical security information. (*Id.*) The highlighted regions requested by staff only show which areas receive certain types of investments and does not include any information regarding critical

infrastructure, personally identifiable customer information, Company Supervisory Control and Data Acquisition information, etc. (7 TR 4786.)

Interested and affected stakeholders need data access as some may wish to examine alternative options for improved reliability that are technically feasible for themselves and their communities.

Witness Koeppel, testifying on behalf of DAOO, also documents difficulty in obtaining data from the Company that supported a more precise spatial analysis of the requests in the case. Instead, he used maps provided by DTE in the instant case and Case No. U-20836 for his analysis. (6 TR 4032.)

Staff recommends the Commission require the Company to develop with Staff a clear and repeatable process that allows interested parties to request and safely obtain and use GIS data with different levels of detail for their own analyses. This data does not necessarily have to be in GIS shapefiles and could be in spreadsheet format as long as detailed geographic data, such as zip code and/or census level data, is provided.

- i. Staff recommends the Commission require the Company to engage interested and affected parties in stakeholder meetings in future distribution plans.**

The Company did not research or engage vulnerable communities to understand and address their concerns when developing the instant case application. Meaningful treatment is a key aspect of the State of Michigan's adopted definition of environment justice. The Company failed to meaningfully involve its customers and failed to consider customer concerns regarding electric

rate increases in the current rate application proposals (Staff Exhibit S-11.20, p 2; 7 TR 4787.)

Staff recommends the Commission require the Company engage interested and affected customers/communities in stakeholder meetings in future distribution plans, so their needs, wants, and concerns can be considered when designing and selecting distribution system programs, projects, and sites. The distribution planning process may provide a more accessible venue to understand and address customer and community concerns than the rate case process. Subsequent rate case filing should discuss how the Company addressed customer concerns in its program and project justifications, where applicable. (7 TR 4787-4788.)

Company witness Adella Crozier rebuts Staff witness Dr. Wang's assertions that the Company "does not understand what 'customer concerns' are." (5 TR 2228.) Though Company witness Crozier lists touchpoints and communication channels with customers where they collect customer information, the discovery supports Staff witness Dr. Wang's conclusion. (5 TR 2228-2230.) When asked to identify actions the Company took in the current application to address vulnerable community customer concerns regarding electric distribution rate increases, the Company objected since the question failed to define "customer concerns" and what it is intended to convey (Staff Exhibit S-11.20, p 2.) The Company's response to the question focused entirely on how "[p]roposed rates are a function of billing determinants and allocated revenue requirements" and gave no indication that any

customer concerns regarding rate increase were ever heard by the Company (Staff Exhibit S-11.20, p 2).

Company witness Crozier disagrees with Staff's recommendation that the Company be required to hold stakeholder meetings for future distribution plans so customer "needs, wants, and concerns can be considered." (5 TR 2228.) The Company finds such meetings unnecessary as it gathered stakeholder input prior to filing its 2021 DGP and has varied modes of gathering ongoing stakeholder input. (5 TR 2230-2231.) The Company believes there is no need for the Commission to order it to conduct stakeholder sessions before filing a future distribution grid plan, as it will hold these sessions on its own initiative if it finds them informative for stakeholders or the Company (5 TR 2231.) Should the Commission order the Company to hold such sessions, the Company would like to work with Staff to discuss expectations and process first. (5 TR 2231.)

Staff continues to recommend the Commission require the Company engage interested and affected customers/communities in stakeholder meetings in future distribution plans, so their needs, wants, and concerns can be considered when designing and selecting distribution system programs, projects, and sites. The distribution planning process may provide a more accessible venue to understand and address customer and community concerns than the rate case process. Subsequent rate case filing should discuss how the Company addressed customer concerns in its program and project justifications, where applicable. (7 Tr 4787-4788.)

Lastly, should the Commission order the Company to hold stakeholder sessions prior to filing future DGPs, Staff is willing to work with the Company to clarify expectations and process.

- j. Staff agrees with Ann Arbor and MI-MAUI that utilities should improve communications and coordination with local units of government when making capital investment plans.**

In direct testimony, Mike Kennedy, Fire Chief for the City of Ann Arbor, on behalf of the City of Ann Arbor, details the impact of weather events, reliability challenges, and issues in communicating with the Company during outage events. He notes that though the Company characterized the three weather events he describes as “unprecedented,” the “once rare weather events are now routine.” (4 TR 841.) Chief Kennedy’s testimony highlights the increased frequency of extreme weather events and the detrimental impacts it has on city operations, communication with the utility, and subsequent resident safety.

James Breuckman, City Manager of Pleasant Ridge, testifying on behalf of the Michigan Municipal Association for Utility Issues (MI-MAUI), discusses the issues the City of Pleasant Ridge had in attempts to coordinate electric distribution undergrounding with the Company. Despite the City’s interest in undergrounding electric cables, the Company left the impression that “it is not actually interested in undergrounding its infrastructure in Pleasant Ridge.” (4 TR 888, 890.) City Manager Breuckman does not believe that DTE provides an acceptable level of reliability to Pleasant and Ridge and its residents. (4 TR 890-891.) Though the

Company felt Pleasant Ridge’s reliability was within normal ranges and required no infrastructure upgrades, the resident phone calls to the City of Pleasant Ridge suggest “DTE customers have a different conception of what constitutes normal and acceptable outage quantity and duration.” (4 TR 891.) City Manager Breuckman’s testimony suggests that the Company’s investments plans and considerations are not in alignment with customer concerns and wants.

Richard Bunch, testifying on behalf of the MI-MAUI, discusses the Company’s communication and coordination with local units of government. He notes the Company fails to meet its customer reliability needs, despite higher rates than other utilities, and failed to deliver clear improvement in reliability or light quality. (4 TR 899.) The Company, during outages, was unable to communicate with local governments for many hours and it also fails to communicate and coordinate with local governments in infrastructure planning. (4 TR 900.) He notes that it is “imperative that the Commission require DTE to better coordinate and communicate with local units of government, and to implement short-term reliability solutions for local government and other critical facilities to ensure continuity of critical services and protection of vulnerable community members during outages while the Company’s longer-term reliability initiatives roll out over a longer period of time.” (4 TR 900.) He recommends the Commission make approval of DTE’s plans and recovery of costs contingent.

In addition to improved communication during outages and resiliency support, Witness Bunch notes municipalities desire more transparency about

reliability performance with enough geographic granularity to support resiliency and emergency services planning, as well as infrastructure and economic development efforts. (4 TR 902.) He notes how many local leaders find DTE uninterested in sharing plans with them to look for synergies, cost sharing and faster progress. (*Id.*) Witness Bunch recommends:

- the “Commission should make approval of DTE’s plans, and recovery of costs, contingent on improved coordination with local units of government or proof that such coordination is not likely to produce efficiencies or hasten reliability improvements.” (4 TR 902);
- the Company must share and coordinate its capital investment plans with local government leaders. (4 TR 902);
- the Company must evaluate coordination opportunities with local infrastructure projects as a standard part of the planning process to reduce costs, alleviate inconvenience and accelerate timelines. (4 TR 903).

In its August 20, 2020 order in Case No. U-20147, the Commission found that “the utilities should continue to coordinate distribution planning efforts with those efforts made by the [Michigan Infrastructure Council (MIC)] in order to benefit all Michigan residents through more efficient and effective planning.”<sup>25</sup> In its November 21, 2018, order in Case No. U-20147, the Commission noted the establishment of the MIC and its purpose to support coordination between utilities, infrastructure owners, finance and policy experts, and others to “coordinate infrastructure-related goals and develop a long-term strategy for Michigan’s infrastructure assets.”<sup>26</sup> In the order, the Commission first emphasized the

---

<sup>25</sup> MPSC Case No. U-20147, August 20, 2020, order, p 49.

<sup>26</sup> Michigan Infrastructure Council Act, 2018 PA 323, MCL 21.601 *et seq.*

coordinating distribution planning efforts with the MIC for more efficient and effective planning.<sup>27</sup> Further, the Commission stated:

Given the pace of change and complexity of these issues, the Commission has a sense of urgency to address many interrelated issues in an integrated fashion. This will allow the Commission and stakeholders to successfully navigate the rapidly evolving energy landscape, ensure reliability and resiliency with mitigation of security threats, facilitate fair and timely access to the grid by third parties and the integration of new energy technologies, and ensure affordable utility bills and accurate price signals. This may also necessitate innovations in the business models of utilities and regulatory approaches with both federal and state jurisdictional implications. Additional guidance will be forthcoming to encourage broad stakeholder participation in these efforts related to planning, grid access, and regulatory innovation.<sup>28</sup>

Local infrastructure owners, like municipalities, are key participants within MIC. The Staff supports recommendations to require improved communications and coordination with local units of government when making utility capital investment plans and to identify opportunities “as a standard part of the planning process . . . to reduce costs, alleviate inconvenience and accelerate timelines.” (4 TR 902.) The Staff notes that this position appears consistent with the Commission’s prior intent and guidance regarding the MIC.

#### **k. Conclusion**

Staff has the following recommendations:

1. To support future environmental justice and equity analyses, Staff recommends the Commission:

---

<sup>27</sup> MPSC Case No. U-20147, November 21, 2018, order, p 38.

<sup>28</sup> MPSC Case No. U-20147, November 21, 2018, order, p 38-39.

- a. Require future environmental justice analyses provide information in community vulnerability gradations based on the MiEJScreen composite score. Staff recommends the Commission request these gradations be defined initially as 0% to <5%, 5% to <10%, in 5% gradations up to 95%-100% of the MiEJScreen composite score, where the Commission may revise these gradations at its future discretion.
  - b. Request the Energy Affordability and Accessibility Collaborative define vulnerable community or environmental justice community based on a threshold of MiEJScreen composite scores for use in environmental justice analyses in future MPSC proceedings for Commission consideration and possible adoption.
2. Staff revises its GIS data related recommendations in brief. Staff recommends the Commission:
- a. Require the Company, in future rate cases and distribution plans, provide data on Customers Experiencing Multiple Interruptions (CEMI) with 6 or more sustained interruptions per year and Customers Experiencing Lengthy Interruption Duration (CELID) of > 16, 48, and 96 hours of interruption by zip code and census tract, identified by census tract GeoID number with census version identified. This information is recommended to be provided by month for the historic period of the rate case or the two years prior to the rate case or distribution plan filing date, whichever is greater, in one or more spreadsheets.
  - b. Order the Company to provide spreadsheet data in future rate cases and distribution plans that notes the zip code and census tract locations that received and are projected to receive reliability related investments by program, including, but not limited to, tree trimming, 4.8kV Hardening, 4.8kV Conversions, Customer Excellence, PTMM, and CODI. Staff recommends this information be provided by program and by year for:
    - i. Five years prior to the rate case or distribution plan filing year to adequately evaluate infrastructure investments and upgrades.
    - ii. All future years for which the Company provides projected investment spend.

3. Staff recommends safety should be of the utmost importance and that known public safety hazards should be promptly addressed according to adopted rules.
4. Staff recommends future Company reports of third-party contacts reported under R 460.3804, in addition to the third party's health status and contact description, also require all the following information be provided:
  - a. Location of contact.
  - b. Distribution system voltage (4.8kV, 8.3kV, 13.2kV, etc.).
  - c. Whether it involved a wire down.
  - d. Whether it involved DPLD arc wire or distribution wire.
5. Staff recommends the Commission require the Company to provide greater transparency into why projects, programs, and deployment locations are selected in future rate cases.
6. Staff recommends the Commission require the Company include climate resiliency planning in future distribution plans, including a climate vulnerability assessment with 50- and 100-year climate forecasts at a minimum and a climate resilience plan.
7. Staff recommends the Commission require the Company to develop a clear and repeatable process that allows interested parties to request, safely obtain, and use GIS data with different levels of detail for their own analyses.
8. Staff recommends the Commission require the Company engage interested and affected customers/communities in stakeholder meetings in future distribution plans so their needs, wants, and concerns can be considered when designing and selecting distribution system programs, projects, and sites. Subsequent rate case filings should discuss how the Company addressed customer concerns in its program and project justifications, where applicable. Should the Commission adopt Staff's recommendation, Staff is willing to work with the Company to clarify expectations and process prior to the start of such stakeholder meetings.

**1. The Staff recommends the Company perform additional analysis on undergrounding.**

Due to the number of down service drops that occurred in the late February and early March 2023 storms, Staff, through its witness Nicholas Evans, recommends that the Company provide a cost-benefit analysis of undergrounding residential service drops in its next rate case. Reliability improvements should be one of the benefits discussed, and the methodology for calculating, estimating, or measuring such benefits should be described in the analysis. (7 TR 4415.)

Company witness Satvir Doel stated that the Company cannot effectively perform a cost-benefit analysis without a pilot. The Company could potentially perform benchmarking and other activities to acquire some knowledge, but until the Company attempts to execute this work at a scale and in different field conditions it cannot provide a robust cost benefit analysis. He said the Company is willing to have a discussion on the potential for proposing another overhead service undergrounding pilot with the Staff to be included in future cases. (2 TR 284.)

In response, Staff's position is that while DTE Electric may not be able to provide a full cost-benefit analysis without a pilot, there is still information that should be reported and presented for review in the Company's next rate case including the types of costs and benefits the Company would include in such an analysis. The Company should share the information it has available at the time in its next filed rate case.

**m. Staff recommends damage prevention and MISS DIG improvements.**

The Commission should adopt all four of Staff's recommendations regarding damage prevention and MISS DIG improvements, as all are reasonable, designed to improve transparency between the Company and Staff, and demonstrate compliance with damage reporting requirements prescribed in Act 174 in an effort to reduce the number of excavation damages. After its review, Staff determined the following:

The Company's initial filing included little to no detail regarding damage prevention and MISS DIG expenditures. A response to Staff discovery included in Staff Exhibit No. S-19.0 (TJB-1), page 3, confirms there is a "small portion" of damage prevention and MISS DIG O&M spend in the FERC 580 account in Company Exhibit No. A-13, Schedule C5.6, p 1, line 3 which includes \$62.8 million in column (l) for the projected test period (Becker 7 TR 4347.) However, Staff is not sure what the Company considers a "small portion" of \$62.8 million. Additionally, responses to Staff discovery regarding damage claims included in Staff Exhibit No. S-19.0 (TJB-1), pages 1-2 and 4, confirm that when a third party is at fault and causes a damage, the third party is billed. Alternatively, when the Company is at fault and causes a damage, repair costs are passed on to ratepayers (Becker, 7 TR 4348.) Lastly, as a part of its review, Staff compared the facility damage reporting requirements to the MPSC as required under Public Act 174 of 2013, MISS DIG Underground Damage Prevention and Safety Act, and Rule 460.40, to what the Company was currently doing, and noted areas of improvement that were needed in

the Company's data reporting (Becker, 7 TR 4349-4350.) As a result, Staff's testimony concluded with four recommendations:

1. Staff recommends the Commission order the Company to begin to track expenditures for damage caused by the Company to its own facilities.
2. Staff recommended the Commission order the Company to have future meetings with Staff to share damage reporting data including, the billing amounts for damages when a third-party causes damages and expenditures for damages, and for sharing billing amounts when the Company causes damages.
3. Staff recommends the Commission order the Company to share a breakdown of damage prevention expenditures in future rate cases under FERC account 580 including, but not limited to, internal locating and contract locating in future rate cases.
4. Staff recommends the Commission order the Company to improve damage reporting quality by 1) continuing to meet with Staff regarding damage report data and 2) committing the time and resources to submitting data into the format that aligns with MPSC's processes (Becker 7 TR 4351-4352.)

In rebuttal, Company witness Brian L. Hill responded to each of Staff's four recommendations and agrees with all but the first—track expenditures for damage caused by the Company to its own facilities. Mr. Hill states the Company does not track expenditures for damage caused by the Company due to the low number of

instances and it does not have a way to separate them historically. He further claimed tracking expenditures at this level would require new processes and procedures along with additional training for field personnel. (Hill, 5 TR 2831.)

The MISS DIG Underground Facility Damage Prevention and Safety Act (Act 174 of 2013), 460.731 states in part that:

(5) Not later than October 1, 2014, the commission shall establish requirements for reporting incidents involving damage to underground facilities.

(6) Beginning April 1, 2015, the commission shall maintain information on damaged facilities reported under subsection (5), including, but not limited to, any damage that occurs during excavation, digging, or blasting that is excluded from the definition of excavation under section 3(m).

The MPSC has established reporting requirements found on the MPSC's Safe Digging webpage (Becker 7 TR 4350) which provides the "MPSC Manual for Reporting Incidents Involving Damage to Underground Facilities" and "Damage Reporting CSV template." Damage reporting requires reporting of the excavator's name and cost of damage among other details, and those reporting requirements do not exempt the Company from reporting itself if it is the damaging excavator. Therefore, if the Company continues to not track and report expenditures for damage caused by the Company to its own facilities, it is not demonstrating compliance with Act 174 or the MPSC's damage reporting requirements.

The ALJ and the Commission should adopt all four of Staff's recommendations. If Staff's first recommendation is not adopted as the Company recommends, the Company is failing to comply with Act 174.

**n. Nuclear Production Tax Credits**

The following does not impact revenue requirements in this case. But at page 92 of DTE witness Uzenski's direct testimony, she states that "the 2022 IRA contains a provision for production tax credits (PTCs) related to nuclear power generation. Staff requests that those tax credits, if they materialize for DTE Electric, be applied as a reduction of PSCR expense instead of tax expense in base rates." Staff recommends approval of the Company's proposed accounting treatment for nuclear PTC as presented by DTE witness Uzenski. (7 TR 4590.)

**o. Tree Trimming Recommendation**

Staff witness Jessica Duell recommends that the Commission and the ALJ the following:

- a. Approves the spend of \$106,190,000 for the projected test year in O&M for tree trimming.
- b. Approve spend of \$53,900,000 for projected test period with this amount being amortized.
- c. Support the Company's surge request of \$43,700,000 for 2025.
- d. DTE to provide information regarding tree trim audits.
- e. Analysis regarding more aggressive and feasible trimming of zones 2 and 3.
- f. DTE develop a proposal for a residential service drop tree trimming pilot.

Ms. Duell supports the Companies proposal to spend \$106,190,000 in O&M expenses for the projected test year for tree-trimming. (7 TR 4399.)

DTE tree-trimming surge program operates on a 5-year cycle. The company plans to spend approximately \$53,900,000 for the surge program during the projected test year. The company then plans to spend \$43,700,000 in 2025 to complete the surge program. Ms. Duell supports this spending because it allows the company to clear overgrown vegetation so DTE can start their risk-based cycle tree trimming as described by DTE witness Shannen Hartwick. (7 TR 4400.)

Ms. Duell recommends DTE provide information on how the company audits their tree-trimming work completed in the field by contractors and company personnel. Ms. Duell would then like the Company to provide the results from the audit and any corrective actions taken by the company's management team in the most recent calendar year. (7 TR 4401.)

Ms. Duell recommends the Company provide an analysis of the feasibility of more aggressive tree trimming in zones 2 and 3 in their next rate case. Ms. Duell believes that a study done on zones 2 and 3 showing a more aggressive approach to tree trimming may result in a decrease in tree related wire downs and better service reliability during storms. (7 TR 4401.)

Ms. Duell recommends DTE develop a proposal for a residential service drop tree trimming pilot. In its proposal, the Company should provide the estimated costs for the pilot and a good area of their service territory in which to conduct it. (7 TR 4402.)

DTE rebutted Ms. Duell's recommendation for a service drop tree trimming pilot because the Company felt it is not reasonable or prudent. The company stated

on page 4, lines 9-13 of Company witness Shannen Hartwick's rebuttal testimony that the Company a) is concerned about the impact of services on customer reliability, b) understands it's difficult for some customers to comply with the current requirement that aligns the responsibility for this outside the Right of Way trimming with the presumed property owner, and c) would consider pilots in the future to address this. (5 TR 2164.)

Ms. Duell understands DTE concerns and recommends the Company conduct a study that will look at residential service drop tree trimming and the benefits it may have on the reliability of the grid. Ms. Duell notes that in the Feb/Mar 2023 storms, DTE had to investigate 31,700 service drop issues. This study would investigate the scope, cost, resources required, amount of reduced costs due to less restoration activities involving service drops, and projected reliability improvements. Ms. Duell recommends DTE conduct such a study and provide the results in its next rate case. The results of the study would guide any future recommendations for a pilot if warranted based on the study. (5 TR 2164.)

**p. Incorporation of testimony by reference should not be permitted.**

DAAO witness Koeppel attempted to incorporate, by reference, testimony from previous cases (6 TR 4046.) Staff responded that if this is allowed then Staff would like to also incorporate, by reference, all previous testimony and rebuttal testimony on related subject matter. (7 TR 4542.) Staff recommends that such broad attempts at incorporation by reference should be rejected or be subject to

some limitations. In addition, Staff would Staff may seek to refer to records of previous cases in reply brief if other parties refer to testimony from previous cases in their initial brief.

## **X. Conclusion**

Staff recommends that the ALJ and Commission find that DTE Electric's total revenue deficiency will be \$386,676,000. Staff recommends that the ALJ and Commission Staff's lower rate base, return on equity and operating expenses, as well as Staff's proposed cost of service, rate design and tariff revisions. Staff's recommendations strike the right balance between DTE Electric's interests and its ratepayers' interests.

Respectfully submitted,

**MICHIGAN PUBLIC SERVICE  
COMMISSION STAFF**

Daniel E. Sonneveldt (P58222)  
Anna B. Stirling (P84919)  
Monica M. Stephens (P73782)  
Assistant Attorneys General  
Public Service Division  
7109 W. Saginaw Hwy., 3rd Floor  
Lansing, MI 48917  
Telephone: (517) 284-8140

**DATED: August 15, 2023**

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,  
for miscellaneous accounting authority

---

Case No. **U-21297**  
**(e-file paperless)**

**APPENDIX A**

**Michigan Public Service Commission**  
**DTE Electric Company**  
**Projected Revenue Deficiency (Sufficiency)**  
**Projected 12 Month Period Ending November 30, 2024**  
**(\$000)**

Case No.: U-21297  
MPSC Staff Initial Brief  
**Appendix A**

<b>Line No.</b>	<b>(a) Description</b>	<b>(b) Source</b>	<b>(c) Applicant Projection (Initial Filing)</b>	<b>(d) Staff Adjustment</b>	<b>(e) Staff Projection</b>
1	Rate Base	Exh. A-12, Sch. B1	\$ 22,611,230	\$ (158,843)	\$ 22,452,387
2	Adjusted Net Operating Income	Exh. A-13, Sch. C1	\$ 836,780	\$ 123,015	\$ 959,795
3	Overall Rate of Return	Line 2 ÷ Line 1	3.70%	0.57%	4.27%
4	Projected Rate of Return	Exh. A-14, Sch. D1	5.70%	-0.18%	5.52%
5	Income Requirements	Line 1 x Line 4	\$ 1,288,524	\$ (48,781)	\$ 1,239,743
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	\$ 451,744	\$ (171,795)	\$ 279,949
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	<u>1.3496</u>	<u>-</u>	<u>1.3496</u>
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	\$ 609,689	\$ (231,860)	\$ 377,829
9	Revenue Deficiency - Tree Trim Surge Program	Exh. A-11, Sch. A1.1	<u>\$ 8,847</u>	<u>\$ -</u>	<u>\$ 8,847</u>
10	Revenue Deficiency / (Sufficiency)-Total	Line 8 + Line 9	<u>\$ 618,536</u>	<u>\$ (231,860)</u>	<u>\$ 386,676</u>

Michigan Public Service Commission  
DTE Electric Company  
Tree Trim Regulatory Asset - Incremental Revenue Requirement  
Projected 12 Month Period Ending November 30, 2024  
(\$000)

Case No.: U-21297  
MPSC Staff Initial Brief  
Appendix A.1

Line No.	(a) Description					(b) Test Period Amount	(c) Reference		
1	<b>Return on Tree Trim Regulatory Asset</b>								
2	Average Balance Regulatory Asset					177,765	Line 14		
3	Short Term Debt Rate					4.98%	Exhibit A-14 D1		
4	Return on Tree Trim					<u>8,847</u>			
		<u>2019-A</u>	<u>2020-A</u>	<u>2021-A</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>		
5	<b>Tree Trim Regulatory Asset</b>								
6	Approved Tree Trim - Surge Funding	43,300	74,100	70,500	58,200	67,000	52,700	Exhibit A-13 C5.6.1, Line 2	
7	Carrying Charges through April 30, 2020 1/		1,200						
8	Additional Funding Request	-	-	-	-	-	-	Exhibit A-13 C5.6.1, Line 3	
9	Total Tree Trim Reg Asset Deferral	<u>43,300</u>	<u>75,300</u>	<u>70,500</u>	<u>58,200</u>	<u>67,000</u>	<u>52,700</u>		
10	Total Tree Trim Reg Asset Cumulative	43,300	118,600	189,100	247,300	314,300	367,000	Cumulative Line 9	
11	Approved for Securitization 2/				<u>(156,900)</u>	<u>(156,900)</u>	<u>(156,900)</u>	Case U-21015	
12	Cumulative Balance at December 31				90,400	157,400	210,100		
13	Cumulative Balance at November 30					150,700	204,830	Assumes 90% of annual spend	
14	Average Balance						177,765		

1/ Interest at U-20162 authorized STD rate of 3.56% until U-20561 order was in effect.

2/ Securitization approved per U-21015 order dated June 23, 2021 (up to \$156.9 per order page 91)

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,  
for miscellaneous accounting authority

---

Case No. **U-21297**  
**(e-file paperless)**

**APPENDIX B**

Michigan Public Service Commission  
DTE Electric Company  
Projected Rate Base  
Projected Average Balances Period Ending November 30, 2024  
(\$000)

Case No.: U-21297  
MPSC Staff Initial Brief  
**Appendix B**

Line No.	(a) Description	(b) Source	(c) Applicant Projection (Initial Filing)	(d) Staff Adjustment	(e) Staff Projection
1	<u>Utility Plant in Service:</u>				
2	Plant in Service	Exh. A-12, Sch. B2, L6	26,771,019	(428,261)	26,342,757
3	Plant Held for Future Use	Exh. A-12, Sch. B2, L7	76,508	-	76,508
4	Construction Work in Progress	Exh. A-12, Sch. B2, L8	2,060,036	257,628	2,317,664
5	Acquisition Adjustments	Exh. A-12, Sch. B2, L9	89,606	-	89,606
6	Total Utility Plant	Sum Lines 2 thru 5	28,997,168	(170,634)	28,826,534
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	(7,845,749)	22,287	(7,823,462)
8	Net Utility Plant	Line 6 + Line 7	21,151,419	(148,347)	21,003,072
9	Net Capital Lease Property	Exh. A-12, Sch. B4.1, col. (c), L10	11,636	-	11,636
10	Property under Operating Leases	Exh. A-12, Sch. B4.1, col. (c), L11	-	-	-
11	Net Nuclear Fuel Property	Exh. A-12, Sch. B4.1, col. (c), L12	201,880	-	201,880
12	Total Utility Property and Plant	Sum Lines 8 thru 11	21,364,936	(148,347)	21,216,588
13	Less: Capital Lease Obligations	Exh. A-12, Sch. B4.1, col. (c), L78 + L93	13,486	-	13,486
14	Net Plant	Line 12 - Line 13	21,351,450	(148,347)	21,203,103
15	Allowance for Working Capital	Exh.A-12, Sch. B4	1,259,780	(10,496)	1,249,285
16	Total Rate Base	Line 14 + Line 15	22,611,230	(158,843)	22,452,387

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,  
for miscellaneous accounting authority

---

Case No. **U-21297**  
**(e-file paperless)**

**APPENDIX C**

MICHIGAN PUBLIC SERVICE COMMISSION

DTE Electric Energy Company  
Development of Projected Net Operating Income  
for the Test Year Ended November 30, 2024  
(\$000)

Line No.	(a) Description (Witness)	Revenue				Expenses								NOI				
		(b) Sales Revenue	(c) Base Fuel & Purchase Power Rev.	(d) Other Revenue and R2 Rider	(e) Total	(f) Fuel and Purchased Power	(g) Other O&M Expense	(h) Depreciation & Amort.	(i) Property Taxes	(j) Other Taxes	(k) State & Local Income Taxes	(l) FIT	(m) Other Utility (Income) / Deductions	(n) Total	(o) NOI	(p) AFUDC	(q) Loss on Reacquired Securities	(r) Adjusted NOI
1	<b>Company Filed</b> <b>Operating Income (Initial Filing)</b>	3,640,008	1,361,901	110,965	5,112,874	1,361,901	1,302,355	1,168,921	320,250	50,173	64,503	46,769	1,277	4,316,149	796,724	43,035	(2,980)	836,780
2	<b>Staff Adjustments</b>																	
3	RIA Revenue Adjustment (Isakson)	2,404			2,404						149	474		623	1,781			1,781
4	Shared Asset Revenue (Rogers)	(1,900)			(1,900)						(118)	(374)		(492)	(1,408)			(1,408)
5					-						-	-		-	-			-
6	<b>Steam Power Generation</b>																	
7	Reduce Periodic Outage Adjustment (Kindschy)						(8,947)				556	1,762		(6,629)	6,629			6,629
8	Trenton Channel Closing (Kindschy)						2,224				(138)	(438)		1,648	(1,648)			(1,648)
9					-						-	-		-	-			-
10	<b>Uncollectible Accounts Expense</b>																	
11	UCX (Ruckert)						(11,805)				733	2,325		(8,747)	8,747			8,747
12					-						-	-		-	-			-
13	<b>Regulated Marketing</b>																	
14	EV Emerging Technology Fund (Freeman)						(1,000)				62	197		(741)	741			741
15					-						-	-		-	-			-
16	<b>Corporate Support</b>																	
17	Incentive Compensation (McMillan-Sepkoski)						(43,821)				2,721	8,631		(32,469)	32,469			32,469
18	Restricted Stock (McMillan-Sepkoski)						(6,534)				406	1,287		(4,841)	4,841			4,841
19	Membership Fees (McMillan-Sepkoski)						(20)				1	4		(15)	15			15
20	Low Carbon Resources Initiative (McMillan-Sepkoski)						(601)				37	118		(446)	446			446
21	Oracle Forecasting Tool (Rogers)						(6)				0	1		(5)	5			5
22	Infrastructure Automation Maturity (Rogers)						(34)				2	7		(25)	25			25
23	Infrastructure Operations Center (IOC) Automation (Rogers)						(34)				2	7		(25)	25			25
24	Changing Bill Size (Klocke)						(2)				0	0		(2)	2			2
25	Customer Service Sales & Service (Klocke)						(330)				20	65		(245)	245			245
26	Pre-Pay II (Klocke)						(344)				21	68		(255)	255			255
27	Level 2 Cost Estimate Disallowance- 20% (Rogers)						(3,151)				196	621		(2,334)	2,334			2,334
28	Unsupported O&M (Rogers)						(44,043)				2,735	8,675		(32,634)	32,634			32,634
29					-						-	-		-	-			-
30	<b>Pension &amp; Benefits</b>																	
31	New Hire Retiree VEBA (Rueckert)						(2,604)				162	513		(1,929)	1,929			1,929
32	Employee Savings Plan (Rueckert)						(5,049)				314	994		(3,741)	3,741			3,741
33	Active Healthcare (Ruckert)						(2,699)				168	532		(2,000)	2,000			2,000
34					-						-	-		-	-			-
35					-						-	-		-	-			-
36	Impact of FERMI Adj on Depreciation and AFUDC							(6,109)			379	1,203		(4,526)	4,526	11,079		15,605
37	Impact of Cap Ex Adj on Depreciation (Gerken)							(16,580)			1,030	3,265		(12,284)	12,284			12,284
38	Proforma Interest (Nichols)										164	519		682	(682)			(682)
39	Interest Synchronization (Nichols)										0	1		1	(1)			(1)
40	<b>Total Adjustments</b>	504	-	-	504	-	(128,802)	(22,689)	-	-	9,603	30,456	-	(111,431)	111,936	11,079	-	123,015
41	<b>Staff NOI - Test Year</b>	<u>3,640,512</u>	<u>1,361,901</u>	<u>110,965</u>	<u>5,113,378</u>	<u>1,361,901</u>	<u>1,173,553</u>	<u>1,146,233</u>	<u>320,250</u>	<u>50,173</u>	<u>74,106</u>	<u>77,225</u>	<u>1,277</u>	<u>4,204,718</u>	<u>908,660</u>	<u>54,114</u>	<u>(2,980)</u>	<u>959,795</u>

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,  
for miscellaneous accounting authority

---

Case No. **U-21297**  
**(e-file paperless)**

**APPENDIX D**

Michigan Public Service Commission  
DTE Electric Company  
Projected Rate of Return Summary  
For Period Ending November 30, 2024

Case No.: U-21297  
MPSC Staff Initial Brief  
Appendix D

Line No.	(a) Description	(b) Capital Structure			(e) Cost Rate %	(g) Weighted Costs			
		(b) Amounts (\$000)	(c) Percent Permanent Capital	(d) Percent of Total Capital		(f) Permanent Capital	(g) Total Cost %	(h) Conversion Factor	(i) Pre-Tax Return
1	Long-Term Debt	8,876,109	50.0%	39.26%	4.06%	2.03%	1.59%	1.0000	1.59%
2	Preferred Stock	0	0.0%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	<u>8,876,081</u>	<u>50.0%</u>	39.26%	9.80%	<u>4.90%</u>	3.85%	1.3496	5.19%
4	Total	17,752,190	<u>100.0%</u>			<u>6.93%</u>			
5	Short-Term Debt	330,941		1.46%	4.98%		0.07%	1.0000	0.07%
6	Investment Tax Credit (ITC) - Debt	15,986		0.07%	4.06%		0.00%	1.0000	0.00%
7	Investment Tax Credit (ITC) - Equity	<u>15,986</u>		0.07%	9.80%		0.01%	1.3496	0.01%
8	Total Investment Tax Credit (ITC)	31,973							
9	Deferred Income Taxes (Net)	<u>4,496,126</u>		<u>19.88%</u>	0.000%		<u>0.00%</u>		<u>0.00%</u>
10	Total	<u>22,611,230</u>		<u>100.00%</u>			<u>5.52%</u>		<u>6.87%</u>

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,  
for miscellaneous accounting authority

---

Case No. **U-21297**  
**(e-file paperless)**

**APPENDIX E**

Michigan Public Service Commission  
DTE Electric Company  
Capital Expenditure and Rate Base Adjustments  
Projected Balances Period Ending November 30, 2024  
(\$000)

Line	Adjustment Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Total Cap Ex Adj.	Plant	CWIP	Accum Dep.	Rate Base	Depreciation	AFUDC	
1	<b>Production:</b>								
2	Steam - Non-Routine Monroe Bottom Ash Conversion (ELG)	(39,859,725)	(29,545,574)		(717,597)	(28,827,977)	(898,895)	-	
3	<b>SUBTOTAL: STEAM NON-ROUTINE</b>	<b>(39,859,725)</b>	<b>(29,545,574)</b>	-	<b>(717,597)</b>	<b>(28,827,977)</b>	<b>(898,895)</b>	-	
4									
5	Steam - Routine - Monroe 3 Coal Mill Classifiers	(1,883,493)	(1,883,493)		(54,914)	(1,828,579)	(57,303)	-	
6	Steam - Routine - Monroe 3 DCS & Controll Room	(1,176,098)	(1,176,098)		(34,290)	(1,141,808)	(35,782)	-	
7	Steam - Routine - Monroe 3 Waterwall Tubes	(8,749,999)	(4,375,000)		(66,552)	(4,308,447)	(133,105)	-	
8	Steam - Routine - Monroe 3 Expansion Joints	(2,015,746)	(1,007,873)		(15,332)	(992,541)	(30,664)	-	
9	Steam - Routine - Monroe 3 Reheat Outlet Pendants	(2,499,811)	(1,249,906)		(19,014)	(1,230,892)	(38,027)	-	
10	Steam - Routine - Monroe 3 DCS & Control Room	(3,858,314)	(1,929,157)		(29,346)	(1,899,811)	(58,693)	-	
11	Steam - Routine - Monroe 3 Coal Mill Classifiers	(2,311,659)	(1,155,830)		(17,582)	(1,138,247)	(35,165)	-	
12	Steam - Routine - Monroe 3 Feedwater Heater #6 South	(3,198,597)	(1,599,299)		(24,329)	(1,574,970)	(48,657)	-	
13	Steam - Routine - Monroe 3 Economizer Tubes	(2,800,185)	(1,400,093)		(21,298)	(1,378,794)	(42,596)	-	
14	Steam - Routine - Monroe 3 Horizontal Reheater Tubes	(2,797,471)	(1,398,736)		(21,278)	(1,377,458)	(42,555)	-	
15	Steam - Routine - Monroe 3 SCR Cleaning System	(2,447,047)	(1,223,524)		(18,612)	(1,204,911)	(37,224)	-	
16	Steam - Routine - Monroe 3 SCR Inlet & Outlet Dampers	(1,765,401)	(882,701)		(13,428)	(869,273)	(26,855)	-	
17	Steam - Routine - Monroe 3 Combustion Coils	(1,249,720)	(624,860)		(9,505)	(615,355)	(19,011)	-	
18	Steam - Routine - Monroe 3 Coal Mill Feeder Controls	(1,100,000)	(550,000)		(8,367)	(541,633)	(16,733)	-	
19	Steam - Routine - Monroe 4 Waterwall Tubes	(2,496,608)	(1,248,304)		(18,989)	(1,229,315)	(37,978)	-	
20	Steam - Routine - Monroe 4 Coal Mill Classifiers	(1,759,128)	(879,564)		(13,380)	(866,184)	(26,760)	-	
21	Steam - Routine - Monroe 3 & 4 - Avoidable Cap Ex Under \$1M	(6,608,451)	(3,304,226)		(50,264)	(3,253,962)	(100,528)	-	
22	<b>SUBTOTAL: STEAM ROUTINE</b>	<b>(48,717,728)</b>	<b>(25,888,659)</b>	-	<b>(436,479)</b>	<b>(25,452,180)</b>	<b>(787,637)</b>	-	
23									
24	Other - Non-Routine - Blue Water Energy Center (CCGT)	(8,100,000)	(8,100,000)		(470,332)	(7,629,668)	(161,255)	-	
25	Other - Non-Routine - Blackstart Project 1	(1,968,000)	(1,968,000)		(44,013)	(1,923,987)	(39,179)	-	
26	Other - Non-Routine - Blackstart Project 2	(1,980,750)	(1,114,875)		(13,369)	(1,101,506)	(22,195)	-	
27	Other - Non-Routine - Blackstart Project 3	(2,577,000)	(2,577,000)		(49,164)	(2,527,836)	(51,303)	-	
28	Other - Non-Routine - Slocum Battery Project	(3,540,000)	(2,723,500)		(62,291)	(2,661,209)	(54,219)	-	
29	Other - Non-Routine - 2025/2026 Battery	(72,227,000)			No Impact as This Portion of CapEx is in CWIP				
30	<b>SUBTOTAL: OTHER - NON-ROUTINE</b>	<b>(90,392,750)</b>	<b>(16,483,375)</b>	-	<b>(639,169)</b>	<b>(15,844,206)</b>	<b>(328,151)</b>	-	
31									
32	<b>TOTAL: PRODUCTION</b>	<b>(178,970,203)</b>	<b>(71,917,608)</b>	-	<b>(1,793,246)</b>	<b>(70,124,362)</b>	<b>(2,014,682)</b>	-	

Michigan Public Service Commission  
DTE Electric Company  
Capital Expenditure and Rate Base Adjustments  
Projected Balances Period Ending November 30, 2024  
(\$000)

Line	Adjustment Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Total Cap Ex Adj.	Plant	CWIP	Accum Dep.	Rate Base	Depreciation	AFUDC	
33	<b><u>Nuclear:</u></b>								
34	Fermi Generator Project	-	(257,627,500)	257,627,500	(3,054,500)	3,054,500	(6,109,000)	11,079,000	
35	<b>TOTAL: NUCLEAR</b>	-	<b>(257,627,500)</b>	<b>257,627,500</b>	<b>(3,054,500)</b>	<b>3,054,500</b>	<b>(6,109,000)</b>	<b>11,079,000</b>	
36									
37	<b><u>Distribution:</u></b>								
38	Strategic Capital Programs - Infrastructure Redesign and Modernization - City of Detroit Infrastructure (CODI) Upgrades	(172,298,000)			No Impact as This Portion of CapEx is in CWIP				
39	Strategic Capital Programs	(69,592,000)	(13,719,150)	-	(280,124)	(13,439,026)	(560,249)	-	
40	Strategic Capital Programs - Infrastructure Redesign and Modernization - Pilot: Strategic and Service Undergrounding	(3,842,000)	(2,883,500)	-	(94,904)	(2,788,596)	(117,753)	-	
41	<b>TOTAL: DISTRIBUTION</b>	<b>(245,732,000)</b>	<b>(16,602,650)</b>	-	<b>(375,029)</b>	<b>(16,227,621)</b>	<b>(678,002)</b>	-	
42									
43	<b><u>Demand Side Management:</u></b>								
44	Other Demand Response Programs and Pilots - Battery Energy Storage	(1,990,360)	(1,990,360)	-	(718,419)	(1,271,941)	(398,072)	-	
45	DTE Insight App	(7,513,000)	(7,176,500)	-	(3,494,029)	(3,682,471)	(1,435,300)	-	
46	<b>TOTAL: DEMAND SIDE MANAGEMENT</b>	<b>(9,503,360)</b>	<b>(9,166,860)</b>	-	<b>(4,212,448)</b>	<b>(4,954,412)</b>	<b>(1,833,372)</b>	-	
47									
48	<b><u>Information Technology:</u></b>								
49	Plant and Field - DTE Electric Utility Network Project	(359,375)	(265,625)	-	(42,317)	(223,308)	(53,125)	-	
50	Plant and Field - Supervisory Control and Data Acquisition	(282,072)	(208,488)	-	(33,214)	(175,274)	(41,698)	-	
51	Plant and Field - ESRI Application Health Project	(194,766)	(143,958)	-	(22,934)	(121,024)	(28,792)	-	
52	<b>SUBTOTAL: PLANT AND FIELD</b>	<b>(836,213)</b>	<b>(618,071)</b>	-	<b>(98,464)</b>	<b>(519,606)</b>	<b>(123,614)</b>	-	
53									
54	Customer Service (Strategic, Enhancements & Compliance) - Changing Bill Size	(900,000)	(815,500)	-	(148,553)	(666,947)	(163,100)	-	
55	Customer Service (Strategic, Enhancements & Compliance) - Customer Service Sales & Service	(7,326,000)	(3,663,000)	-	(366,300)	(3,296,700)	(732,600)	-	
56	Customer Service (Strategic, Enhancements & Compliance) - Pre-Pay	(6,704,000)	(6,704,000)	-	(3,910,711)	(2,793,289)	(1,340,800)	-	
57	Customer Service (Strategic, Enhancements & Compliance) - Pre-Pay II	(2,640,000)	(1,320,000)	-	(132,000)	(1,188,000)	(264,000)	-	
58	<b>SUBTOTAL: CUSTOMER SERVICE</b>	<b>(17,570,000)</b>	<b>(12,502,500)</b>	-	<b>(4,557,565)</b>	<b>(7,944,935)</b>	<b>(2,500,500)</b>	-	
59									
60	<b>Corporate Applications - Oracle Forecasting Tool</b>	<b>(3,800,000)</b>	<b>(3,706,000)</b>	-	<b>(1,238,380)</b>	<b>(2,467,620)</b>	<b>(741,200)</b>	-	
61	<b>Information Technology for IT - Infrastructure Automation Maturity</b>	<b>(406,000)</b>	<b>(203,000)</b>	-	<b>(20,300)</b>	<b>(182,700)</b>	<b>(40,600)</b>	-	
62	<b>Information Technology for IT - Infrastructure Operations Center (IOC) Automation</b>	<b>(406,000)</b>	<b>(203,000)</b>	-	<b>(20,300)</b>	<b>(182,700)</b>	<b>(40,600)</b>	-	

Michigan Public Service Commission  
DTE Electric Company  
Capital Expenditure and Rate Base Adjustments  
Projected Balances Period Ending November 30, 2024  
(\$000)

Line	Adjustment Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Total Cap Ex Adj.	Plant	CWIP	Accum Dep.	Rate Base	Depreciation	AFUDC	
63	Corporate Applications - Level 2 cost estimate 20% Disallowance	(3,973,000)	(2,813,600)	-	(452,152)	(2,361,448)	(562,720)	-	
64	Customer Service (Sustainment and Return to Health) - Level 2 cost estimate 20% Disallowance	(8,388,200)	(6,372,200)	-	(1,055,677)	(5,316,523)	(1,274,440)	-	
65	Customer Service (Strategic, Enhancements & Compliance) - Level 2 cost estimate 20% Disallowance	(13,428,993)	(9,368,793)	-	(1,502,551)	(7,866,242)	(1,873,759)	-	
66	Plant & Field - Level 2 cost estimate 20% Disallowance	(7,111,200)	(4,661,700)	-	(668,940)	(3,992,760)	(932,340)	-	
67	Information Technology for IT - Level 2 cost estimate 20% Disallowance	(9,019,000)	(5,873,200)	-	(873,733)	(4,999,467)	(1,174,640)	-	
68	Information Protection Security - Level 2 cost estimate 20% Disallowance	(1,356,200)	(1,022,400)	-	(188,359)	(834,041)	(204,480)	-	
69	Infrastructure Operations - Level 2 cost estimate 20% Disallowance	(10,413,800)	(8,242,000)	-	(1,380,595)	(6,861,405)	(1,648,400)	-	
70	Enterprise Data Analytics - Level 2 cost estimate 20% Disallowance	(543,600)	(393,600)	-	(61,688)	(331,912)	(78,720)	-	
71	<b>SUBTOTAL: LEVEL 2 COST ESTIMATES</b>	<b>(54,233,993)</b>	<b>(38,747,493)</b>	<b>-</b>	<b>(6,183,695)</b>	<b>(32,563,798)</b>	<b>(7,749,499)</b>	<b>-</b>	
72									
73	<b>TOTAL: INFORMATION TECHNOLOGY</b>	<b>(77,252,206)</b>	<b>(55,980,064)</b>	<b>-</b>	<b>(12,118,704)</b>	<b>(43,861,360)</b>	<b>(11,196,013)</b>	<b>-</b>	
74									
75	<b>Corporate Staff:</b>								
76	Other Miscellaneous - NERC-Critical Infrastructure Program	(1,341,667)	(991,667)	-	(157,982)	(833,685)	(198,333)	-	
77	<b>TOTAL: CORPORATE STAFF</b>	<b>(1,341,667)</b>	<b>(991,667)</b>	<b>-</b>	<b>(157,982)</b>	<b>(833,685)</b>	<b>(198,333)</b>	<b>-</b>	
78									
79	<b>Charging Forward:</b>								
80	Charging Forward Expansion - Charging Hubs	(1,330,000)	(665,000)	-	(13,578)	(651,422)	(27,157)	-	
81	Charging Forward Expansion - Community Chargers	(3,600,000)	(1,800,000)	-	(36,753)	(1,763,247)	(73,507)	-	
82	<b>TOTAL: CHARGING FORWARD</b>	<b>(4,930,000)</b>	<b>(2,465,000)</b>	<b>-</b>	<b>(50,332)</b>	<b>(2,414,668)</b>	<b>(100,663)</b>	<b>-</b>	
83									
84	<b>Contingency:</b>								
85	Corporate Staff - Modernization - Waterford Service Center	(4,400,000)	(4,170,000)	-	(292,091)	(3,877,909)	(313,059)	-	
86	Distribution - Technology and Information - SOC: ASOC	(2,840,000)	(2,840,000)	-	(111,141)	(2,728,859)	(115,977)	-	
87	Production Plant Other - Non Routine - Blue Water Energy Center (CCGT)	(6,800,000)	(6,500,000)	-	(121,269)	(6,378,731)	(129,402)	-	
88	<b>TOTAL: CONTINGENCY</b>	<b>(14,040,000)</b>	<b>(13,510,000)</b>	<b>-</b>	<b>(524,500)</b>	<b>(12,985,500)</b>	<b>(558,438)</b>	<b>-</b>	
89									
90	<b>TOTAL</b>	<b>(531,769,436)</b>	<b>(428,261,349)</b>	<b>257,627,500</b>	<b>(22,286,740)</b>	<b>(148,347,109)</b>	<b>(22,688,504)</b>	<b>11,079,000</b>	
91									
92	<b>WORKING CAPITAL ADJUSTMENTS</b>								
93	Other Accounts Receivable					(7,257,549)			
94	Move Balances to 13-Mth Averages					(1,680,000)			
95	Reg Asset: Charging Forward Expansion - Emerging Technology Fund					(900,000)			
96	Reg Asset: Delivered Fuel Electricfication Pilot (DFEP)					(658,000)			
97	<b>TOTAL: WORKING CAPITAL</b>					<b>(10,495,549)</b>			
98									
99	<b>TOTAL RATE BASE ADJUSTMENTS</b>					<b>(158,842,658)</b>			

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,  
for miscellaneous accounting authority

---

Case No. **U-21297**  
**(e-file paperless)**

**APPENDIX F**

Michigan Public Service Commission  
DTE Electric Company  
Summary of Staff Position  
Projected Balances Period Ending November 30, 2024

Appendix F  
MPSC Staff Brief  
Case No. U-21297

Line	(a) Description	(b) Source	(c) Rate Base	(d) Pre-Tax	(e) Revenue Requirement Impact (million \$)
<b><u>Walk from DTE Revenue Deficiency (Initial Filing) to Staff Initial Brief</u></b>					<b>(million \$)</b>
1	<b>Company Revenue Deficiency (Initial Filing)</b>				<b>\$ 618.536</b>
2	<b><u>Staff Adjustments</u></b>				
3	Rate base	Appendix E * Exhibit A-14, Sch D-1	(158.843)	7.11%	\$ (11.290)
4	Rate of return	Appendix B * (Appendix D less Exh A-14)	22,452.387	-0.24%	(53.623)
5	Revenue	Appendix C, line 3			(0.504)
6	O&M Expense	Appendix C, line 40			(128.802)
7	Depreciation	Appendix C, line 40			(22.689)
8	AFUDC	Appendix C, line 40	(11.079)	1.3496	(14.953)
9	<b>Total Staff adjustments (rev. req. impact)</b>	Appendix A, line 10			<b>\$ (231.860)</b>
10	<b>Staff Revenue Deficiency (Initial Brief)</b>	Appendix A, line 10			<b>\$ 386.676</b>
<b><u>Walk from Staff Initial Filing to Staff Initial Brief Revenue Deficiency</u></b>					<b>(million \$)</b>
11	<b>Initial Filing - Staff Revenue Deficiency</b>	Exh S-1, Schedule A-1			<b>\$ 383.235</b>
12	Rate base	See Below	177.750	6.87%	12.210
13	Depreciation	Appendix C, line 40			0.291
14	Sales Revenue	Appendix C, line 40			1.900
15	O&M	See Below			3.992
16	AFUDC	Appendix C, line 40	(11.079)	1.3496	(14.953)
17	<b>Initial Brief - Staff Revenue Deficiency</b>				<b>386.676</b>
<b><u>Walk from Staff Initial Filing O&amp;M to Staff Initial Brief O&amp;M</u></b>					<b>(\$000)</b>
18	<b>Staff Initial Filing</b>	Initial Filing, Schedule C1			<b>\$ 1,169,561</b>
19	Oracle Forecasting Tool (Rogers)	Initial Brief, Appendix C, line 21	25% Reduction		2
20	Infrastructure Automation Maturity (Rogers)	Initial Brief, Appendix C, line 22	25% Reduction		11
21	Infrastructure Operations Center (IOC) Automation (Ro	Initial Brief, Appendix C, line 23	25% Reduction		11
22	Changing Bill Size (Klocke)	Initial Brief, Appendix C, line 24	25% Reduction		1
23	Customer Service Sales & Service (Klocke)	Initial Brief, Appendix C, line 25	25% Reduction		110
24	Pre-Pay II (Klocke)	Initial Brief, Appendix C, line 26	25% Reduction		115
25	Level 2 Cost Estimate Disallowance- 20% (Rogers)	Initial Brief, Appendix C, line 27	25% Reduction		1,050
26	Active Healthcare (Ruckert)	Initial Brief, Appendix C, line 33			2,743
27	UCX (Ruckert)	Initial Brief, Appendix C, line 11			849
28	Employee Savings Plan (Rueckert)	Initial Brief, Appendix C, line 11			(900)
29	<b>Staff Initial Brief</b>	Initial Brief, Appendix C, line 41			<b>\$ 1,173,553</b>
<b><u>Walk from Staff Initial Filing Rate Base to Staff Initial Brief Rate Base</u></b>					<b>(\$000)</b>
30	<b>Staff Initial Filing</b>	Initial Filing, Schedule B1			<b>\$ 22,274,637</b>
31	Other - Non-Routine - 2025/2026 Battery				\$ 43,090
32	Strategic Capital Programs - Infrastructure Redesign and Modernization - City of Detroit Infrastructure (CODI) Upgrades				110,959
33	Strategic Capital Programs				20,646
34	Fermi Generator				3,055
35	<b>Staff Initial Brief</b>	Initial Brief, Appendix B, line 16			<b>\$ 22,452,387</b>



**City of Ann Arbor**  
**Michigan Municipal Association**  
**for Utility Issues**

Valerie J.M. Brader

Valerie R. Jackson

[valarie@rivenoaklaw.com](mailto:valarie@rivenoaklaw.com)

[valeriejackson@rivenoaklaw.com](mailto:valeriejackson@rivenoaklaw.com)

**Utility Workers Union of America**

Benjamin L. King

[bking@michworkerlaw.com](mailto:bking@michworkerlaw.com)

**Foundry Association of Michigan**

**ChargePoint Inc.**

**Energy Michigan**

**Bloom Energy**

**Foundry Association of Michigan**

**Michigan Energy Innovation**

**Business Council**

**Institute for Energy Innovation**

**Advanced Energy United**

Timothy J. Lundgren

Justin K. Ooms

Laura A. Chappelle

[tlundgren@potomaclaw.com](mailto:tlundgren@potomaclaw.com)

[jooms@potomaclaw.com](mailto:jooms@potomaclaw.com)

[lchappelle@potomaclaw.com](mailto:lchappelle@potomaclaw.com)

**Soulardarity**

**We Want Green, Too**

Amanda Urban

Mark Templeton

[t-9aurba@lawclinics.uchicago.edu](mailto:t-9aurba@lawclinics.uchicago.edu)

[templeton@uchicago.edu](mailto:templeton@uchicago.edu)

[aclc\\_mpsc@lawclinic.uchicago.edu](mailto:aclc_mpsc@lawclinic.uchicago.edu)

**Citizens Utility Board**

**Michigan Environmental Council**

**Sierra Club**

**Natural Resources Defense**

**Council**

Christopher M. Bzdok

Daniel H.B.Abrams

Breanna Thomas

[chris@envlaw.com](mailto:chris@envlaw.com)

[dabrams@elpc.org](mailto:dabrams@elpc.org)

[breanna@envlaw.com](mailto:breanna@envlaw.com)

**Gerdau MacSteel, Inc.**

Jennifer U. Heston

[jheston@fraserlawfirm.com](mailto:jheston@fraserlawfirm.com)

**Michigan Cable  
Telecommunications Association**

Sean P. Gallagher  
Jordyn DuPuis

[sgallagher@fraserlawfirm.com](mailto:sgallagher@fraserlawfirm.com)  
[jdupuis@fraserlawfirm.com](mailto:jdupuis@fraserlawfirm.com)

**International Transmission  
Company**

Olivia R.C.A. Flower  
Richard J. Aaron  
Hannah E. Buzolits  
Lisa Agrimonti

[OFlower@dykema.com](mailto:OFlower@dykema.com)  
[RAaron@dykema.com](mailto:RAaron@dykema.com)  
[hbuzolits@dykema.com](mailto:hbuzolits@dykema.com)  
[lagrimonti@fredlaw.com](mailto:lagrimonti@fredlaw.com)  
[mpscfilings@dykema.com](mailto:mpscfilings@dykema.com)

**EVgo Services LLC**

Brian R. Gallagher  
Nikhil Vijaykar  
Alicia Zaloga  
Sara Rafalson

[bgallagher@moblofleming.com](mailto:bgallagher@moblofleming.com)  
[nvijaykar@keysfox.com](mailto:nvijaykar@keysfox.com)  
[azaloga@keysfox.com](mailto:azaloga@keysfox.com)  
[sara.rafalson@evgo.com](mailto:sara.rafalson@evgo.com)

**Residential Customer Group  
Great Lakes Renewable Energy  
Association**

Don L. Keskey  
Brian W. Coyer  
Carol Dane

[donkeskey@publiclawresourcecenter.com](mailto:donkeskey@publiclawresourcecenter.com)  
[bwcoyer@publiclawresourcecenter.com](mailto:bwcoyer@publiclawresourcecenter.com)  
[adminasst@publiclawresourcecenter.com](mailto:adminasst@publiclawresourcecenter.com)

**Walmart Inc.**

Melissa M. Horne

[mhorne@hcc-law.com](mailto:mhorne@hcc-law.com)

**Great Lakes Renewable Energy  
Association Inc.**

Don L. Keskey  
Brian W. Coyer

[donkeskey@publiclawresourcecenter.com](mailto:donkeskey@publiclawresourcecenter.com)  
[bwcoyer@publiclawresourcecenter.com](mailto:bwcoyer@publiclawresourcecenter.com)

**The Kroger Company**

Kurt J. Boehm  
Jody Kyler Cohn  
Michael L. Kurtz

[kboehm@BKLawfirm.com](mailto:kboehm@BKLawfirm.com)  
[jkylercohn@BKLawfirm.com](mailto:jkylercohn@BKLawfirm.com)  
[mkurtz@BKLawfirm.com](mailto:mkurtz@BKLawfirm.com)

**Environmental Law & Policy  
Center  
Ecology Center  
Union of Concerned Scientists  
Vote Solar**

Alondra Estrada  
Heather Vogel  
Daniel Abrams

[astrada@elpc.org](mailto:astrada@elpc.org)  
[hvogel@elpc.org](mailto:hvogel@elpc.org)  
[dabrams@elpc.org](mailto:dabrams@elpc.org)  
[mpscdocket@elpc.org](mailto:mpscdocket@elpc.org)

---

Pamela A. Pung

Subscribed and sworn to before  
me this **16th** day of **August, 2023**.

---

De Ann M. Payne, Notary Public  
State of Michigan, County of Eaton  
Acting in the County of Eaton  
My Commission Expires: 11-29-24