



Stephen A. Campbell
T (313) 309-4274
F (313) 309-6882
Email:SCampbell@ClarkHill.com

Clark Hill
500 Woodward Avenue, Suite 3500
Detroit, MI 48226
T 313.965.8300
F 313.965.8252

October 26, 2026

VIA ELECTRONIC CASE FILING

Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, Michigan 48917

Re: Case No. U-22046 – In the matter of the Application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.

Dear Executive Secretary:

Enclosed for filing please find the **Association of Businesses Advocating Tariff Equity's PUBLIC Initial Brief** and **Proof of Service** in the above-referenced matter.

Sincerely,

CLARK HILL PLC

Stephen A.
Campbell

Digitally signed by: Stephen A. Campbell
DN: CN = Stephen A. Campbell email =
SCampbell@clarkhill.com C = US O =
Clark Hill PLC
Date: 2026.10.26 14:39:16 -04'00'

Stephen A. Campbell

SAC/lkd
cc: Parties of Record

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of DTE	)	
ELECTRIC COMPANY for authority to	)	Case No. U-22046
increase its rates, amend its rate schedules	)	
and rules governing the distribution and	)	ALJ Theresa A.G. Staley
supply of electric energy, and for	)	
miscellaneous accounting authority.	)	
_____	)	

[PUBLIC] INITIAL BRIEF OF THE
ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

The Association of Businesses Advocating Tariff Equity (“ABATE”), by its attorneys, CLARK HILL PLC, files its Initial Brief in this proceeding initiated by DTE Electric Company (“DTE” or the “Company”) before the Michigan Public Service Commission (“Commission”) in accordance with the schedule established by the presiding Administrative Law Judge (“ALJ”).

TABLE OF CONTENTS

I.	INTRODUCTION	1
II.	LEGAL STANDARD.....	1
III.	ARGUMENT	4
	A. Test Year.....	4
	B. Rate Base.....	6
	1. Production capital expenditures.....	6
	2. Distribution capital expenditures.....	15
	C. Capital Structure and Rate of Return.....	27
	1. The utility industry’s access to capital and the context of the current economic environment indicate the Company’s ROE should be reduced.....	27
	2. The Company’s risk indicates it is a safe, stable investment.....	31
	3. The Company’s proposed capital structure is unreasonable, contradicts the Commission’s preferences, and skews its ROE request.....	32
	4. The Company’s proxy group demonstrates a lower ROE is reasonable.	35
	5. Reasonable empirical models demonstrate a reasonable ROE for the Company is 9.40%.....	36
	6. A reasonable ROE for the Company should be no higher than 9.40%.....	42
	7. The Company’s requested ROE is excessive and unreasonable.....	44
	D. Other Revenue-Related Items.....	49
	1. Production O&M expense.....	49
	2. Distribution O&M expense.....	60
	3. Investment Recovery Mechanism.....	64
	E. Revenue Deficiency Calculation.....	67
	F. Cost of Service, Rate Design, and Tariffs.....	68
	1. Cost of service.....	68
	2. Tariff issues.....	80
IV.	RELIEF REQUESTED.....	86

I. INTRODUCTION

The Commission may authorize a Michigan utility to collect rates and charges that are just and reasonable considering the utility's reasonable cost of doing business. In requesting Commission approval, the applicant utility bears the burden of demonstrating that its proposed costs and rates are reasonable and prudent. Despite this requirement, DTE put forth several proposals in this proceeding which would result in rates that do not meet this standard and should be rejected or modified.

These proposals include numerous cost recovery requests based on projections which were inadequately supported and unreasonable. The Company also requested a return on equity ("ROE") and equity ratio which are excessive, inadequately supported, and unnecessary, and should be rejected. In addition, certain of DTE's cost of service and tariff proposals are unreasonable and would not appropriately align revenues with customer costs.

Accordingly, to ensure appropriate rates the Commission should reject these proposals and adopt the recommendations set out below. This will ensure DTE's rates are reasonable and prudent and that the Company's costs are allocated to the customers which cause them.

II. LEGAL STANDARD

A final order of the Commission "must be authorized by law and be supported by competent, material, and substantial evidence on the whole record." *Attorney General v Pub Serv Comm*, 165 Mich App 230, 235-36 (1987); Const 1963, art 6, § 28. "An order is unreasonable if it is not supported by the evidence." *Id.* Specifically, "substantial evidence" means "any evidence that reasonable minds would accept as adequate to support the decision," which "is more than a mere scintilla of evidence, but may be less than a preponderance of the evidence." *In re Complaint of Pelland*, 254 Mich App 675, 685 (2003). Stated differently, the classic definition of substantial evidence is "the amount of evidence that a reasonable mind would accept as sufficient to support

a conclusion.” *In re Payne*, 444 Mich 679, 690-95 (1994). Thus, while a “reviewing court addresses only questions of law, these questions include whether the record support the findings of the lower court,” meaning “whether the evidence is such that it will justify the finding as a legitimate inference from the facts proved.” *Id.* In other words, “[w]hat the drafters of the Constitution intended was a thorough judicial review of administrative decision, a review which considers the whole record—that is, both sides of the record—not just those portions of the record supporting the findings of the administrative agency.” *Id.* (internal citation omitted). Although such a review does not attain the status of *de novo* review, “it necessarily entails a degree of qualitative and quantitative evaluation of evidence considered by an agency.” *Id.* (internal citation omitted).

Regarding the Commission’s review of the evidence, as the Commission has stated, “[t]here is no legal presumption that findings of fact should be made in the utility’s favor if there is conflicting evidence.” *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered January 31, 2017 (Case No. U-18014), p 6-9. If the Commission were to “rule in the utility’s favor whenever substantial evidence supports the utility’s position, the Commission would not be performing the legally-required weighing and sifting of evidence and would be committing legal error.” *Id.* Further, even the “fact that the company has presented ‘substantial evidence’ (i.e., ‘more than a mere scintilla’) on a particular proposal does not make the reasonableness and prudence of that proposal a forgone conclusion [] whether or not any other parties weigh in.” *Id.* “Moreover, in the case where the company seeks approval for a projected cost, the company must not only provide sufficient evidence to demonstrate to the Commission that both the specific project and its cost are reasonable and prudent, but it must also show by a preponderance of the evidence that the cost will in fact be incurred before the end of the test

period.” *Id.* Thus, projections must be adequately supported and investments must be made within the relevant time period. For instance, the Commission has reiterated multiple times that “even for otherwise worthwhile investments, whether a proposed investment is likely to be made during the time period in question goes to the heart of whether that investment is truly ‘reasonable, prudent, and worthy of recovery.’” *In the Matter of the Application of DTE Electric Co.*, order of the Public Service Commission, entered January 23, 2025 (Case No. U-21534), p 52; *In the Matter of the Application of DTE Gas Co.*, order of the Public Service Commission, entered November 7, 2024 (Case No. U-21291), p 24. Also, “including ‘placeholder amounts in the company’s initial filing, and then attempting to justify these amounts later is unreasonable.” *In the Matter of the Application of DTE Electric Co.*, order of the Public Service Commission, entered February 19, 2026 (Case No. U-21860), p 45.

Regarding cost projections, the “Commission’s expectation is that the parties will fully document the basis for their test year projections by offering into evidence detailed supporting explanations and underlying assumptions rooted in expected business, financial, and economic circumstances,” and “[r]ate applications may not rely on undocumented estimates of future ratemaking expenses and revenue criteria.” *In the Matter of the Application of DTE Electric Co.*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-20561), p 13. “The record thus created should lend itself to a comparative review of the reasonableness and prudence of the projections” and “[h]istorical data may play a role” and may be the controlling factor “in circumstances that clearly demonstrate that it is a more fair and reasonable reflection of the utility’s cost of service, relative to projected data.” *Id.*

Regarding the evidentiary basis of the Commission’s decision more broadly, Mich Admin Code, R 792.10427(2) requires that “[e]vidence, including records and documents in the

possession of the commission, that a party desires or intends to rely on shall be offered and made a part of the record in the proceeding and other factual information or evidence shall not be considered in the determination of the case, except as otherwise permitted by law.” Thus, as the Commission has stated, “evidence relied upon, including evidence from an expert, must be in the record.” *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered March 29, 2018 (Case No. U-18322); see also *In the Matter of the Application of Upper Peninsula Power Co*, order of the Public Service Commission, entered March 15, 2018 (Case No. U-17991-R) (explaining that “[e]vidence, including records and documents in the possession of the commission, that a party desires or intends to rely on *shall* be offered and made a part of the record in the proceeding and other factual information or evidence *shall not* be considered in the determination of the case, except as otherwise permitted by law”) (emphasis in original).

III. ARGUMENT

A. Test Year.

References in the Record: Dauphinais 3 Tr 1296-99; Bruzzano 4 Tr 1980-81, 2012-14.

In this case DTE requested a \$474 million revenue increase for expenses it asserted it will incur during a March 1, 2027 through February 29, 2028 projected test year. (Bruzzano 4 Tr 1980.) As the projected costs in this case entail myriad hypotheticals and are incongruous with the DTE’s history of overearning its permitted rate of return the Commission should be exacting in reviewing the DTE’s cost forecast.

Specifically, DTE’s projected \$474 million of additional future costs should be considered against the accuracy of its past cost projections. These demonstrate DTE’s consistent pattern of claiming significantly more costs than it eventually incurs:

TABLE JRD-3				
<u>Historical Test Year and Projected Test Year</u> Rate Sufficiency / (Deficiency)				
<u>Case</u>	<u>Year Filed</u>	<u>Historical Test Year Sufficiency / (Deficiency)</u>	<u>Projected Test Year Sufficiency / (Deficiency)</u>	<u>Difference Between Historical and Projected</u>
U-18014	2016	\$33,404,000	(\$343,972,000)	(\$377,376,000)
U-18255	2017	(\$50,009,000)	(\$230,942,000)	(\$180,933,000)
U-20162	2018	(\$18,335,000)	(\$328,440,000)	(\$310,105,000)
U-20561	2019	(\$111,501,000)	(\$350,688,000)	(\$239,187,000)
U-20836	2022	\$111,696,000	(\$388,222,000)	(\$499,918,000)
U-21297	2023	\$93,577,000	(\$618,536,000)	(\$712,113,000)
U-21534	2024	\$80,492,000	(\$456,434,000)	(\$536,926,000)
U-21860	2025	(\$150,519,000)	(\$574,067,000)	(\$423,548,000)
U-22046	<u>2026</u>	<u>\$87,520,000</u>	<u>(\$474,345,000)</u>	<u>(\$561,865,000)</u>
Total		\$76,325,000	(\$3,765,646,000)	(\$3,841,971,000)
Sources: Case No. U-18014, Exhibit A-1 and Exhibit A-8, Schedule A1; Case No. U-18255, Exhibit A-1 and Exhibit A-8, Schedule A1; Case No. U-20162, Exhibit A-1 and Exhibit A-11, Schedule A1; Case No. U-20561, Exhibit A-1 and Exhibit A-11, Schedule A1; Case No. U-20836, Exhibit A-1 and Exhibit A-11, Schedule A1; Case No. U-21297, Exhibit A-1 and Exhibit A-11, Schedule A1; Case No. U-21534, Exhibit A-1 and Exhibit A-11, Schedule A1; Case No. U-21860, Exhibit A-1 and Exhibit A-11, Schedule A1; and Case No. U-22046, Exhibit A-1 and Exhibit A-11, Schedule A1				

(See Dauphinais 3 Tr 1296-99.) As demonstrated above DTE has reported a historical test year revenue sufficiency of at least \$80.5 million in four out of five of its most recent base rate filings, totaling \$373.3 million. (*Id.*) Factoring in the one historical test year revenue deficiency of \$150.5 million reported during that period, DTE still realized a net windfall of \$222.8 million over its last five rate case filings. In other words, DTE has repeatedly projected significant revenue deficiencies, received revenue increases from the Commission to address those predicted deficiencies, and then reported revenue *sufficiencies* for those periods. DTE's claims regarding its future costs must be evaluated in this context.

Instead of DTE's cost projections approximating, failing to meet, or exceeding its actual costs in roughly equal measure, its projections are consistently much higher than its actual eventual costs. Continuing to provide DTE excess revenues year after year based on clearly inflated projections is simply not reasonable. As such the Commission must be exacting in rejecting inadequately supported projections and instead utilizing historical costs as the basis for determining appropriate revenues. The Commission should therefore ensure: (i) expenses and investments proposed by DTE are truly necessary to provide reliable electric service at the lowest reasonable cost, (ii) DTE is irrevocably committed to incur its projected expenses and investments or otherwise cannot avoid them, and (iii) DTE's projected investments and expenses are precisely quantified with respect to both amount and the specific quarter in which they will be incurred.

B. Rate Base.

1. Production capital expenditures.

a. Trenton channel sea wall.

References in the Record: York 3 Tr 1354-57, Exhibit AB-8; Guillaumin 4 Tr 3376-87, 3488-91, Exhibit A-12; Coppola 4 Tr 5422-23.

The Company requested \$13.593 million for the Trenton channel sea wall during calendar year 2026 to "complete engineering, obtain permits, and construct the shoreline/seawall" despite only spending \$1.083 million on engineering and design of the sea wall and natural shoreline in 2025. (See York 3 Tr 1354-57; Guillaumin 4 Tr 3376-87.) As this cost projection and the related work is still preliminary the Commission should reject DTE's request.

The Commission has rejected DTE's requested cost recovery for the Trenton channel sea wall multiple times, including in Case No. U-21860 where it found the following:

The Commission agrees with ABATE and the Attorney General that the projected \$9.5 million for 2026 is not likely to be spent during the bridge period or test year. DTE Electric acknowledges that the project is still in the design phase and is not expected to be complete until 2027. [] In addition, DTE Electric states that "[a]n

appropriation request that includes the full project budget will be executed once the design and engineering are complete.” [] This indicates to the Commission that the project still does not have internal approval for the significant projected costs post-design phase. [*In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered February 19, 2026 (Case No. U-21860), p 24.]

The status of this project has not substantially advanced. When asked to identify each fact or development that has materially advanced the project’s commercial readiness since the February 19, 2026 Order in Case No. U-21860, DTE identified only two updates, that it “has continued engineering and permitting activities,” and “the project has advanced from PAT-0 to PAT-1 status.” (York 3 Tr 1355; Exhibit AB-8 at 16, 21.) Under DTE’s own description of DTE’s stage gate process, PAT-1 does not authorize construction; only PAT-2 authorizes complete physical construction of the project. (*Id.*; Guillaumin 4 Tr 3376-77.) Thus, the project is still not authorized for construction. Furthermore, the project does not have a CARF for the full project budget and it is still in the queue for corporate level authorizations. (Exhibit AB-8 at 1, 16, 18.) This is the same deficiency the Commission identified in denying cost recovery in both Case Nos. U-21860 and U-21534. (See York 3 Tr 1355.)

DTE’s actual expenditures confirm the project is not advancing in accordance with DTE’s projected timeline. (York 3 Tr 1356-57.) For the first six months of calendar year 2026, DTE projected \$6.74 million of spending while actual spending was roughly \$35 after a credit of \$47,680 recorded in June 2026 (that is, gross charges of approximately \$47,715 offset by the credit). (*Id.*) Again, this pattern is the same one the Commission relied on in declining cost recovery in Case No. U-21860, where actual spending through May 2025 was negative \$285,000. A year later the project has still consumed less than \$40 of the \$13.593 million DTE projects for calendar year 2026. (*Id.*) The projected in-service date of December 1, 2026 cannot be reconciled with the evidence demonstrating limited expenditures and extended timelines. As explained by ABATE witness York, DTE would have to spend approximately \$13.56 million and complete

removal of deteriorated sheet piles, maintenance of existing piles, and installation of new piles along the Detroit River and Slocum Canal shorelines in the six months between July 1 and December 1, 2026. (*Id.*; Guillaumin 4 Tr 3378.) All of this would need to occur despite the project, as of August 3, 2026, having no CARF for its full budget, having not received corporate level authorization, and having not been internally approved for physical construction. (York 3 Tr 1356-57.) Indeed, DTE has asserted that it “is currently working with EGLE to secure permitting and finalize the plan.” (Guillaumin 4 Tr 3490.) That permitting is still pending and the plan has not been finalized is far from an indication the requested amounts will be spent in the relevant period.

DTE’s rebuttal does not change this conclusion. While DTE characterized ABATE’s recommendation as focused on “past 2026 monthly expenses rather than the status of the project work,” the status of the project work is precisely the problem. (Guillaumin 4 Tr 3490.) Again, according to DTE only “[a]pproximately half of the detailed engineering has been completed,” and DTE was still pursuing a joint permit application with EGLE and the U.S. Army Corps of Engineers. (*Id.*) The signed PAT form DTE relies on supports “the engineering and design of the future site,” not construction. (*Id.*; Exhibit A-60, Schedule RP8, p 3.) DTE did not dispute that the project lacks PAT-2 approval, lacks a CARF for its full budget, and remains in the queue for corporate level authorizations. Nor did DTE explain how it will finish design, obtain its permits, authorize construction, and complete approximately \$13.56 million of shoreline construction by its claimed year-end 2026 in-service date. Whether or not the project is eventually necessary is not the issue; the question is whether the projected costs will be incurred during the period for which recovery is sought, and the record demonstrates they will not.

DTE’s projection far exceeds the amounts it has spent or could reasonably be expected to spend in the relevant period. The project has not materially advanced beyond the stage it was at in

DTE's most recent rate case, in which the Commission denied cost recovery for unreasonable cost projections. As it did in Case No. U-21860, the Commission should disallow cost recovery for the entire \$13.593 million of projected bridge period expenditures.

b. Monroe outfall and bridge support structure.

References in the Record: York 3 Tr 1357-59, Exhibit AB-8; Guillaumin 4 Tr 3378, 3491-93, Exhibit A-12.

DTE requested cost recovery of approximately \$11.76 million for this project, of which approximately \$11.45 million falls in the projected test period. (Guillaumin 4 Tr 3378; Exhibit A-12.) Given the nascent stages of this project cost recovery is not reasonable or prudent at this time.

According to DTE this project "is being engineered and is approved at the PAT-0 level," which is two full levels below construction authorization and does not authorize bidding of long lead materials or EPC contracts, let alone physical construction. (Exhibit AB-8 at 23-27.) Indeed, DTE has not identified any construction contract for this project while nonetheless projecting an in-service date of December 31, 2027. (*Id.*) DTE further asserted that "[f]ull internal project authorization for the Monroe Outfall & Bridge Support Structure project is expected in the first quarter of 2027." (*Id.*) As noted above, the projected test period begins March 1, 2027. In other words, DTE has requested \$11.45 million for projected test year costs for a project that is not expected to be authorized until the eve of that period, and has asserted project completion by the end of next year despite not having a construction contract. (York 3 Tr 1357-59.) This request should also be considered in the context of DTE's actual expenditures, which through June 2026 were only \$170,000. (Exhibit AB-8 at 23-27.)

The project is similar to the Trenton channel sea wall project discussed above and in Case No. U-21860. Both are shoreline and structure restoration projects, are in the engineering phase, do not have full internal authorization, do not have executed construction contracts, and have

limited related expenditures to date. (York 3 Tr 1357-59.) A key difference, however, is that the Monroe outfall project is even less far along, specifically at PAT-0 rather than PAT-1, and by DTE's own projection will not be authorized until the projected test period has nearly begun. (*Id.*) DTE has not explained why these cost projections should be approved considering the Commission's discussion of project status and cost projections in Case No. U-21860. Specifically, when asked to explain how this expenditure satisfies the used and useful standard, addressing the Commission's treatment of the comparable Trenton channel sea wall project in Case No. U-21860, DTE simply objected and responded only that the project is anticipated to be in service by December 31, 2027, and that Monroe capital receives regulatory asset treatment. (Exhibit AB-8 at 23-28.)

DTE did not address the Commission's treatment of the comparable project, nor has it offered a basis for demonstrating costs will be incurred as projected. Instead, DTE asserted that it "has received 90% design from the engineering firm" (i.e., the project is not actually fully designed) and it "met with EGLE in early September to *begin* the application process for permitting" after which it "will *begin* a series of review periods." (Guillaumin 4 Tr 3491 (emphasis added).) The project therefore lacks a final design and has yet to enter multiple layers of regulatory review. This status does not indicate cost recovery is reasonable here. More specifically, DTE further confirmed that both the permit and full internal project authorization are not expected until the first quarter of 2027 and that construction is not scheduled to begin until May 2027, leaving roughly eight months to construct a project for which DTE has identified no construction contract before its projected December 31, 2027 in-service date. (Guillaumin 4 Tr 3491-92.)

This project is in a preliminary approval stage without a construction contract and authorization is not expected until the eve of the projected test year. As such its projections and

completion deadline are unreasonable and should not be approved. The Commission should therefore reject \$11.45 million of projected cost recovery for the Monroe outfall and bridge support structure project.

c. Monroe fly ash basin closure (CCR).

References in the Record: York 3 Tr 1359-63, Exhibit AB-8; Lee 4 Tr 2234-36; Guillaumin 4 Tr 3397-98, 3485-88, Exhibit A-12.

DTE projected \$106.715 million of expenditures during the 14-month bridge period and \$93.883 million during the projected test period, following \$3.739 million of actual expenditures in 2025. (Guillaumin 4 Tr 3397-98; Exhibit A-12.) Given the discrepancies in DTE's proposed schedule for this project, DTE's proposed cost recovery is unreasonable here.

While DTE testified that it planned to complete closure of the Monroe fly ash basin by December 28, 2028, in discovery it stated that the "project is expected to reach completion in December 2030" and "is currently forecasted to continue after the projected test period and reach completion in December 2030." (*Id.*; Exhibit AB-8 at 12-13.) Despite extending the project completion date by two years DTE did not reduce any projected test year expenditures. (York 3 Tr 1359-63.) DTE agreed "that the two-year schedule extension will, directionally, lead to costs being spread out over a longer time interval," but objected to ABATE's proposed recovery disallowance based on a contract it executed in July 2026, which DTE asserted supports a \$27.5 million reduction based on updated forecast spending. (Guillaumin 4 Tr 3486.)

As stated above, the Commission has reiterated that "whether a proposed investment is likely to be made during the time period in question goes to the heart of whether that investment is truly 'reasonable, prudent, and worthy of recovery.'" *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered January 23, 2025 (Case No. U-21534), p 52. Indeed, in its February 19, 2026 Order in Case No. U-21860 the Commission

declined to approve half of DTE's requested cost recovery for this project in part because DTE did not demonstrate "that the bulk of the work will be completed in the test year." (Case No. U-21860, p 28.) By extending the completion date for this project by two years the same amount of work and the associated costs will be correspondingly extended over that period. As such the Company's projected test year costs are clearly overstated; the work will not be completed in the test year and its projected costs will not be incurred in that period.

As explained by ABATE witness York, matching the projected test year costs with DTE's updated project timeline results in projected test period expenditures of approximately 48% (i.e., 26% divided by 55%) of the amount DTE has forecast, or approximately \$44.4 million. This straight-line reallocation supports a reduction of approximately \$49.5 million. (York 3 Tr 1362.) ABATE nonetheless recommends the more conservative of two reasonable measures: the \$46.9 million reduction produced by the same 50% adjustment the Commission adopted for this project in Case No. U-21860, which does not require the Commission to assume a uniform spending profile. (*Id.*)

Again, DTE agreed that "the two-year schedule extension will, directionally, lead to costs being spread out over a longer time interval," and itself now proposes to reduce projected test period expenditures for this project by \$27.5 million. (Guillaumin 4 Tr 3486-88.) At a minimum, then, the Commission should adopt that conceded reduction; the only remaining dispute is the additional \$19.4 million. DTE's criticism that ABATE relied on "simple assumed ratios" and on a 50% adjustment "carried over" from Case No. U-21860 misses the point. (*Id.*) ABATE expressly acknowledged that the procurement and authorization deficiencies the Commission identified in Case No. U-21860 have been cured and does not rely on them. (York 3 Tr 1360.) The 50% figure serves as a conservative benchmark for quantifying the effect of a schedule DTE itself has

extended by two years, and it produces a smaller reduction than a straight-line reallocation of the remaining work. (*Id.* at 1362.) Moreover, DTE's revised spending profile surfaced only in rebuttal, after ABATE identified that DTE's discovery response had moved the completion date from December 2028 to December 2030 without acknowledging the change and without adjusting any projected expenditure. (*Id.* at 1360-61; Exhibit AB-8 at 12-13.) DTE's filed projection was therefore premised on a schedule DTE had already abandoned.

Furthermore, DTE's spending to date is consistent with this reduction. Specifically, for this project DTE spent \$30.67 million during the first six months of calendar year 2026 against \$77.95 million reflected in Exhibit A-12, Schedule B5.1 for the full calendar year. (Exhibit AB-8 at 10-11.) DTE's reliance on an updated spend profile developed after the July 2026 contract, and its argument that "a disproportionately large amount of funding is required at the beginning of the project," do not warrant the Commission providing DTE, rather than ratepayers, the benefit of the doubt with regard to revenue increases. (Guillaumin 4 Tr 3487.) DTE's projections require exacting review and its updated claims regarding supplemental projection adjustments should be resolved in favor of ratepayers, not the utility.

The extended completion timeline for this project merits a corresponding reduction. As such the Commission should reduce DTE's projected test period capital expenditures for the Monroe fly ash basin closure project by \$46.9 million and reflect that reduction in the Monroe Power Plant regulatory asset.

d. Cost estimate maturity and contingency.

References in the Record: York 3 Tr 1363-65, Exhibit AB-8; Robertson 4 Tr 3168.

DTE argued that the Commission should "discontinue the use of unsupported percentage-based disallowances for cost estimates, particularly without considering the lack of contingency in

an estimate,” asserting it produces a structural bias toward under-recovery. (Robertson 4 Tr 3168.) As DTE provided no supporting analysis for this assertion the Commission should reject this claim.

When asked to provide all workpapers, data, and analyses supporting its position, including the analysis supporting the claimed distribution of probable project outcomes, and to identify the specific projects and dollar amounts in this case to which the claimed under-recovery applies, DTE responded that its relevant testimony discusses “general mathematical and logical concepts,” and “leveraged a normal distribution in [its witness’s] example only to illustrate the nature of the systematic bias,” and that it “did not perform any analysis or document any conclusions [] as to the distribution of probable outcomes of specific DTE Electric capital projects.” (Exhibit AB-8 at 5.) In other words, DTE’s claim is a theoretical argument with no actual support; DTE provided no evidence or analysis demonstrating that any Commission adjustment has produced the claimed under-recovery.

As ABATE witness York explained, a project’s definition and the accuracy of DTE’s estimates evolve throughout the project planning process; cost estimates developed in the early stages are less accurate than later figures. DTE itself uses a project-level indicator of cost estimate maturity for some of its operations (e.g., the PAT process described above for generation). (York 3 Tr 1363-65.) The Commission should therefore reject DTE’s claim and instead continue to evaluate projected capital expenditures against the standard set out above to ensure project activities are undertaken and costs are incurred during the relevant period.¹

¹ It’s important to note that the production cost projection adjustments discussed above are based on project-specific circumstances, including authorization status, contract status, actual expenditures and revised schedules. (York 3 Tr 1363-65.) Thus, they are not based on estimate accuracy ranges or any percentage derived from an estimate classification.

2. Distribution capital expenditures.

a. DTE's benefit-cost analysis does not comply with the Commission's prior direction and is fundamentally flawed.

References in the Record: Becker 2 Tr 858-59; Fitzhenry 3 Tr 1391-99, Exhibit AB-10; De Stigter 4 Tr 4706-07, 4729-56; Lepczyk 4 Tr 4667, 4676-81; Bruzzano 4 Tr 2022-23; Chiu 4 Tr 4383; Coppola 4 Tr 5530-33; Stephens 4 Tr 5557-63.

In its February 19, 2026 Order in Case No. U-21860 the Commission provided two important directives regarding DTE's BCA, namely that DTE "update its BCAs to include the full revenue requirement (i.e., full customer costs) in support of the company's proposed capital investments" and "consider alternative ways to develop its BCAs to support its various programs and projects, specifically whether to consider doing this type of analysis in-house to alleviate propriety concerns and reduce cost of preparation, to build upon the analyses over time from one analysis to the next, to increase the transparency necessary in order for intervenors to work with and test the analysis (possibly also as part of technical conferences/workshops in conjunction with the company's DSP pre-filing outreach), and for the Commission to thus be able to rely on the analysis in its determinations of reasonableness and prudence." DTE complied with neither of these directives in this proceeding.

Regarding the latter directive, the Commission's direction was driven by its concerns expressed in its February 19, 2026 Order in Case No. U-21860, namely "the model's proprietary and restrictive software applications and platforms inhibiting model transparency for intervenor evaluation." DTE's BCA in this proceeding again presented these same issues, as it continues to rely entirely on 1898 & Co.'s proprietary Integrated Resilience, Reliability, and Risk Investment Model executed through specialized platforms, including KNIME, SQL databases, and custom Python scripts. (Fitzhenry 3 Tr 1391-99; Chiu 4 Tr 4383 ("While Company personnel possess detailed knowledge of the distribution system, the Company does not maintain the specialized,

proprietary BCA models and methodologies developed and refined by a specialized consultant”).) In other words, despite the Commission’s direction, DTE did essentially nothing to remediate the transparency and accessibility concerns which continue to present barriers to meaningful review of DTE’s analyses. DTE’s claim that it would essentially be too much work to make the BCA more accessible does not support its position or justify shrugging off its burden; it demonstrates DTE has not adequately supported its analysis. (De Stigter 4 Tr 4741-43.)

DTE also failed to incorporate a full revenue requirement framework directly into its core BCA modeling despite the Commission’s explicit direction. (Fitzhenry 3 Tr 1391-99.) DTE’s off-model revenue requirement sensitivity for a selective subset or sample of projects does not satisfy this Commission directive. First, performing an evaluation of an extremely limited sample of 14 projects, rather than integrating the BCA across DTE’s full portfolio of distribution programs, is clearly insufficient. (*Id.*) This is nearly identical to the comparative analysis presented by DTE in Case No. U-21860 where the Commission explicitly ordered DTE to update its BCA tool to incorporate its full revenue requirement. While DTE asserted that its *approach* here was different, the fact remains that the BCA did not “include the full revenue requirement (i.e., full customer costs) in support of the company’s proposed capital investments,” as the Commission directed. Instead, it reviewed 14 projects and asserted that, based on the results, this was good enough. (De Stigter 4 Tr 4737-40.) DTE explicitly acknowledged that its approach in this proceeding “was not to statistically project results across the entire population of BCA evaluations” but instead “the objective was to determine whether incorporation of revenue requirement materially changes the conclusions produced by the underlying BCA framework.” (Lepczyk 4 Tr 4678-80; see De Stigter 4 Tr 4736.) Thus, despite the Commission’s direction, DTE instead performed an analysis which it “never claimed [] constituted a statistically representative sample of the entire population of

BCA evaluations” because including the full revenue requirement, as the Commission explicitly directed, was, in DTE’s estimation, too burdensome. (*Id.*) Further, this approach was fundamentally deficient on its own terms. For instance, the annual revenue requirement calculations DTE used do not appear to include the full revenue requirement ratepayers will incur. (Fitzhenry 3 Tr 1391-99.) DTE’s claim that ABATE did not identify incorrect inputs or calculation errors misses the larger point; the proprietary nature of DTE’s BCA offered limited to no meaningful opportunity to validate its outputs and its failure to incorporate a full revenue requirement left it fatally deficient. (De Stigter 4 Tr 4754-55.)

In addition to these flaws, DTE did not perform any analysis of its previous BCA model and the included projects; DTE’s entire approach focused on forecasted costs without any review of whether its prior BCA analysis produced reliable results. (Fitzhenry 3 Tr 1391-99.) Without this context there is no indication DTE’s BCA provides a useful or accurate analysis. Further, DTE’s assumption that any project or program activity with $BCR > 0.9$ is economically justified and cost-effective is not reasonable. (*Id.*) As ABATE witness Fitzhenry explained, “[b]y definition, an investment with a $BCR < 1.0$ fails the fundamental economic test of cost-effectiveness, as its quantified lifecycle costs exceed its quantified customer benefits.” (*Id.*) Utilizing a lower figure based on assumptions of unmodeled “qualitative benefits” that DTE was not able to monetize is arbitrary and does not provide a reasonable basis for reviewing DTE’s assumptions and analysis. (*Id.*) Indeed, DTE’s claim that this figure “leaves certain benefit streams unquantified because monetizing them would require assumptions that introduce subjectivity or risk overstating the results” demonstrates why its analysis is unreasonable. (De Stigter 4 Tr 4751-54.) These “benefit streams” have no demonstrable bearing on cost and should not influence BCA results. In addition, DTE’s BCA analysis itself presents a significant ratepayer cost of \$1,278,000. (Fitzhenry 3 Tr

1391-99.) The utility of the BCA itself is also questionable. DTE stated that “the BCA results provide directional guidance and should not [] treated as a binary decision criterion under which an investments is supported only if it exceeds a rigid numerical BCR threshold.” (Chiu 4 Tr 4385.) Customers should not be forced to provide significant sums for a flawed BCA which is not considered by DTE to even indicate “decision criteria under which an investment[] is supported.” Because DTE failed to comply with the Commission’s unambiguous direction and its BCA is fundamentally deficient the Commission should not permit DTE to collect these costs from customers.

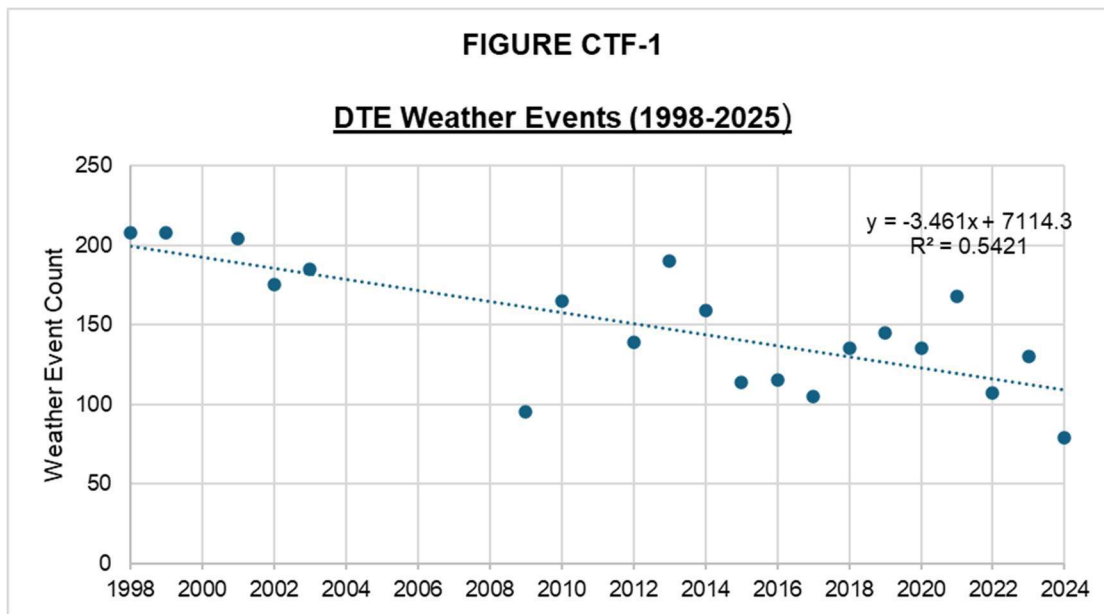
Given the inadequacy of DTE’s BCA the Commission should not rely on its results to justify the cost-effectiveness, or capital prioritization, of DTE’s proposed distribution, subtransmission, and grid modernization programs here, and should explicitly reject DTE’s proposed $BCR > 0.9$ threshold. Further, the Commission should disallow recovery of any projected test year DTE consulting fees and expenses related to the BCA and direct DTE to do the following: (i) develop a fully accessible BCA model for its next rate case that directly integrates full utility revenue requirement mechanics, including return on rate base, debt service, depreciation schedules, and income taxes, directly into the primary model rather than relying on off-model sensitivity analysis; and (ii) conduct rigorous ex-post analyses and back-testing for all capital programs evaluated by the BCA such that DTE validates its models by comparing actual, historical post-investment reliability and resilience outcomes against prior model forecasts before deploying additional capital under these programs.

b. DTE’s projected costs related to weather events are overstated.

References in the Record: Fitzhenry 3 Tr 1399-1403; Chiu 4 Tr 4298-99; Hill 4 Tr 4819; Kryscynski 4 Tr 4402; Robinson 4 Tr 3858; Stowe 4 Tr 5400; Exhibit A-28; Chiu 4 Tr 4385-87.

DTE proposed significant cost increases related to addressing customer outages resulting from weather events. (See e.g. Kryscynski 4 Tr 4402; Fitzhenry 3 Tr 1399-1403.) DTE’s actual data regarding weather events and costs does not support this requested increase.

DTE’s data regarding weather events occurring in its service territory from 1998 through 2024 reveals a clear and statistically significant declining trend in the frequency of weather events over time. (See Fitzhenry 3 Tr 1399-1403):



As set out above, while DTE experienced approximately 200 or more annual weather events in the late 1990s and early 2000s, annual events have steadily declined to 130 in 2023 and 79 in 2024. (*Id.*) DTE’s claims regarding increasing weather events and costs are therefore explicitly contradicted by its own historical dataset and statistical modeling.

The evidence in this proceeding does not support DTE’s claims. DTE has presented no statistical validation or historical evidence demonstrating an upward trend in storm frequency

across its service territory. Instead, as DTE's data demonstrates a clear decline in weather-based resiliency events, the claimed increasing frequency of such events does not justify increasing distribution capital investments and O&M expense.

c. Emergent non-storm capital expenditures.

References in the Record: Stults 2 Tr 282-85; Fitzhenry 3 Tr 1405-07, Exhibit AB-9; Hill 4 Tr 4837, 4875-76, 4880-81, Exhibit A-33; Coppola 4 Tr 5384-90.

DTE's Non-Storm Emergent Replacements cost projection was based on a 5-year average including a 2025 actual non-storm spend of \$21.36 million for a single, extraordinary emergency equipment failure at the Great Lakes Water Authority ("GLWA") in June 2025. (Exhibit AB-9 at 17-21; Fitzhenry 3 Tr 1405-07.) DTE's projected cost recovery should not be based on an average including this expenditure.

As ABATE witness Fitzhenry explained, the use of a 5-year average is intended to normalize expenditures, not establish an ongoing budget inflated by non-recurring industrial customer equipment failures. (*Id.*) The inclusion of this \$21.36 million one-time event increases the non-storm forecast by over \$4.27 million annually, a significant increase for a novel one-time event. Furthermore, the GLWA incident involved two distinct failures of 120 kV pipe-type and high-pressure gas-insulated cables feeding the facility. (*Id.*) A more thorough diagnostic response following the first failure may have mitigated subsequent repair costs by providing visibility into the potential failure of the adjacent cable. (*Id.*) DTE's assertion that the five-year average is meant to "capture the inherent variability of emergent replacement activity and reflect the full range of the Company's historical experience over time" does not justify the inclusion of blatantly novel and unique instances of significant one-time cost incursion. (Hill 4 Tr 4881.)

DTE's projected non-storm expenditures are also impacted by its own internal revision to its classification of storm and non-storm expenditures. DTE acknowledged that it has performed

no analysis to determine how much capital expenditure was shifted from “storm” to “non-storm” as a result of this accounting change. Because that change classified smaller storm days as “non-storm,” however, the non-storm category now includes increased emergent expenditures. (Hill 4 Tr 4838; Exhibit AB-9 at 16.) In other words, DTE’s “non-storm” cost increases have resulted from DTE’s internal accounting practices, not actual increased costs. Indeed, despite DTE stating that “[r]egardless of whether an event is categorized as Storm or Non-Storm, the Company must respond to downed wires, repair damaged equipment, and restore power to customers,” it acknowledged that the threshold does affect “the accounting classification of restoration costs . . .” (Hill 4 Tr 4876.)

Given the novelty of the GLWA expenditure the Commission should remove the associated \$21.36 million cost from 2025 actuals before computing the 5-year historical average. This adjustment would result in a more useful average and reduce the projected test year emergent non-storm capital expenditures by approximately \$4.27 million.

d. Pole top maintenance and modernization.

References in the Record: Stults 2 Tr 291; Gerken 2 Tr 597; Evans 2 Tr 641; Becker 2 Tr 849-62; Fitzhenry 3 Tr 1407-12; Robinson 4 Tr 3886, 3996-4018; Stephens 4 Tr 5563-72, Exhibits MAG-11, MAG-12.

Regarding its PTMM program DTE proposed more than doubling annual execution volumes and dramatically increasing requested capital investment from the currently authorized \$200.0 million in 2026 to \$263.4 million in 2027 (\$200.0 million IRM plus \$63.4 million in base rates), \$376.8 million in 2028 (\$314.0 million IRM plus \$62.8 million in base rates), \$482.6 million in 2029 (all IRM), and \$540.0 million in 2030 (all IRM), yielding a five-year capital total of \$1.863 billion. Alongside this capital expenditure increase, O&M inspection and testing expenses would increase from \$4.9 million in 2026 to \$8.2 million by 2030, totaling \$33.9 million

across the five-year period. (Robinson 4 Tr 3886; Fitzhenry 3 Tr 1407-12.) As these cost and timeframe extensions are excessive and unreasonable the Commission should reject them.

In its February 19, 2026 Order in Case No. U-21860 the Commission declined to adopt DTE's request to extend the IRM further than one year, noting that such an extension "will continue to provide an opportunity to assess whether the reconciliation process is functioning effectively as intended, that the investments are providing the benefits expected, and that input from interested persons is being valued." The Commission also noted that "should the company seek approval of a multi-year extension of the IRM, it must further develop and present a comprehensive strategy for implementing effective capital programs, including the development of BCAs to assess cost-effectiveness, as well as strategies for optimizing capital spending in coordination with enhanced vegetation management to maximize the value of investments intended to improve reliability." Regarding PTMM specifically, the Commission quoted and approved the ALJ's following assertions:

DTE is designating equipment that is old or outmoded as defective, even though it is not damaged. Replacing this functioning, albeit antiquated, equipment serves only to increase costs, without improving reliability. As such, this PFD agrees with MNSC that DTE should reevaluate its criteria for determining what equipment, including poles, needs immediate replacement and what equipment can be replaced in the future.

Further, the Commission stated that "careful evaluation should be undertaken by DTE Electric when determining whether replacing equipment improves reliability and is an overall benefit to customers."

Rather than a careful approach DTE has proposed here to dramatically increase pole condemnation rates. (Fitzhenry 3 Tr 1407-12.) DTE itself acknowledged these increases stem from its own internal "quality control improvements and process refinements" implemented in 2023 (i.e., prior to the Commission's Order in Case No. U-21860) rather than objective physical changes

in the pole population. (AB-9 at 11, 29; Robinson 4 Tr 3883.) DTE's assertion that "replacement decisions are based on inspection results and established asset-condition criteria, not spending levels" misses the point; its replacement criteria are flawed and serve to inflate costs rather than "improved inspection quality." (Robinson 4 Tr 4002, 4014.) DTE's change to its approach condemns thousands of poles that could otherwise be treated, reinforced, or safely left in service in direct contradiction of the Commission's findings and direction in Case No. U-21860. (Fitzhenry 3 Tr 1407-12.) That DTE's claimed "significant actions to reevaluate the criteria used to determine which equipment requires immediate replacement and which equipment can remain in service" happens to support DTE's past and additional revenue requests requires close scrutiny. (Robinson 4 Tr 4014.)

Furthermore, DTE's work history itself does not support its proposal. Rather than these drastic increases, DTE's actual 2026 work indicates condemnation and replacement rates should be maintained at current levels. For the first five months of 2026, PTMM spend was \$90.31 million, demonstrating the \$200.0 million annual funding the Commission approved in February 2026 is appropriate and adequately supports necessary ongoing inspection and remediation work (over 1,600 miles per year). (Exhibit AB-9 at 31, 33.) Dramatically increasing costs to \$263.4 million in 2027 and \$376.8 million in 2028 would overwhelm contractor capacity, exacerbate contractor labor premiums, and incentivize premature replacement of viable utility poles. (Fitzhenry 3 Tr 1407-12.) DTE's prior spending also does not indicate its proposed increases are reasonable or prudent. DTE proposed to increase PTMM O&M expenses from \$4.9 million in 2026 to \$5.8 million in 2027 and \$7.2 million in 2028 despite actual PTMM O&M expenses of only \$136.4 thousand in 2023, \$625.2 thousand in 2024, \$967.3 thousand in 2025, and \$717.0 thousand YTD in 2026. (*Id.*; Exhibit AB-9 at 29.) Thus, DTE's proposed increase in 2027

represents a nearly six-fold increase over 2025 actual spending. DTE's past PTMM O&M expenses simply do not support its requested increase. There is no indication that DTE's requested funding and proposed work to "advance toward the inspection cycles recommended by the Audit," is reasonable, particularly in light of the Commission's expectation "to see documentation from DTE Electric on the current pace of inspections and associated O&M costs in rate cases and the appropriate increased pace," which expectation it has failed to meet here. (Robinson 4 Tr 4016.)

DTE's proposed work and cost increases are directly contrary to the Commission's prior direction for PTMM and significantly exceed both its prior work rate and spending for this program. As such the Commission should take the following action: (i) disallow DTE's proposed \$63.4 million incremental base rate PTMM capital request in the test year period; (ii) deny DTE's requested approval for increases of \$314.0 million in 2028, \$482.6 million in 2029, and \$540.0 million in 2030; and (iii) reduce test-year PTMM O&M expenses to \$1.5 million for the projected test year, given the acknowledged error in DTE's calculations.² The adjustment reduces the Company's projected test year O&M expense by \$4.3 million.

e. Next-generation automated metering infrastructure.

References in the Record: Fitzhenry 3 Tr 1413-16; Rademacher 4 Tr 4181-83, 4236-40; Exhibit A-12, A-13, A-23; Coppola 4 Tr 5400-404.

DTE requested the Commission approve \$2.883 million for the 14-month bridge period ending February 28, 2027, and \$3.800 million in capital expenditures for the 12-month projected test year ending February 29, 2028. (Exhibits A-12, A-13; Exhibit AB-9 at 22.) Combined with

² DTE confirmed that it "identified that inflation was double counted in the PTMM inspection adjustments" and the "total amount for the double counted inflation is \$147,514, which is found in U-22046 STDE-16.3-01 Projected Adjustments." (Exhibit AB-9 at 31.) The Commission must therefore reduce DTE's projected test-year Distribution O&M expenses by \$147,514 to eliminate this acknowledged double-counting error.

the requested test-year operations and maintenance adjustment of \$3.642 million, the total requested ratepayer-funded capital and O&M burden for Next-Gen AMI across the bridge and test periods exceeds \$10.3 million despite DTE confirming that from 2020 through 2025, historical O&M expense for this program were zero dollars, with only \$510,000 incurred in 2025 for preliminary scoping. (*Id.*; Fitzhenry 3 Tr 1413-16.) This proposed revenue increase was inadequately supported and should not be approved.

While DTE claimed this work is necessary due to existing infrastructure obsolescence and “constrained” technology, the evidence in this case demonstrates the contrary. (Rademacher 4 Tr 4240.) Specifically, DTE admitted that its primary electric meter vendor continues to manufacture the meters currently deployed across the system and has committed to selling these models through 2030. (Exhibit AB-9 at 24.) DTE’s 2026 Distribution System Plan also acknowledged that the standard expected useful life of these meters is approximately 20 years and confirms that the majority of its meter fleet will not reach or exceed that age until 2035. (Exhibit A-23.) Further, despite DTE’s claims that failure rates increase with meter age, the vast majority of its meters remain well within their reliable operating life. (Fitzhenry 3 Tr 1413-16.) There is no supply or operational issue warranting DTE’s requested revenue increase and its proposal is unreasonable. Indeed, a review of the complete age distribution of DTE’s 2,643,559 installed smart meters confirms that the vast majority of the fleet is modern. (*Id.*; Exhibit AB-9 at 23-28.) Only 16.92% of DTE’s meters are older first-generation units, and DTE has acknowledged that catastrophic failures among these meters are not increasing. (*Id.*) DTE currently uses routine base capital funding for regular meter replacements, meaning its proposal to embark on an enterprise-wide replacement program is premature and unreasonable. (*Id.*) Indeed, while DTE asserted that its underlying need related to not just meters, but the platform supporting them, it acknowledged that

it expected “complete headend deployment by the end of 2028,” which is beyond the projected test year in this case. (Rademacher 4 Tr 2439-40.)

Beyond a lack of necessity DTE also failed to quantify how customers would benefit from these costs. Despite being asked to provide a list of all expected benefits and quantify cost savings for each benefit, DTE expressly stated that “the cost savings have not yet been quantified.” (Exhibit AB-9 at 25.) DTE also stated that “exact Next-Gen AMI meter cost has not yet been determined as deployment will begin in 2030” and DTE “estimates the cost of the Next-Gen AMI meters will be similar to our current AMI meters.” (*Id.* at 28.) Further, in response to a request for an explanation of what, and how many, advanced DERMS operations would be supported by Next-Gen AMI, DTE admitted that a “specific list of functionalities cannot be provided until a final scope for Next Generation AMI is determined.” (*Id.* at 32.) Thus, DTE has requested customers provide millions of dollars in revenue despite not demonstrating these costs are necessary or will provide benefits.

Given these deficiencies the Commission should not approve DTE’s requested \$3.642 million test-year O&M expense adjustment, and should also disallow all bridge and test-year capital expenditures for Next-Generation AMI totaling \$3.800 million in test-year and \$2.883 million in bridge period cost projections. Any request for revenues associated with this work should be supported by a formal, quantified BCA demonstrating positive net benefits to customers, firm vendor pricing, and a justification for replacement timelines considering the remaining useful life of DTE’s modern meter fleet.

C. Capital Structure and Rate of Return.

References in the Record: Stults 2 Tr 274-75; McGovern 2 Tr 403-15, Exhibit WAL-4; Ufolla 2 Tr 460-85; Sawari 2 Tr 1133-36; Walters 3 Tr 1432-553, Exhibits AB-11, AB-12, AB-13, AB-14, AB-15, AB-16, AB-17, AB-18, AB-19, AB-20, AB-21, AB-22, AB-23, AB-24, AB-25, AB-26; Lepczyk 4 Tr 4676-77; Nelson 4 Tr 2490-715, Exhibit A-14, Schedule D-5; Bandyk 4 Tr 5111-377, Exhibits CUB-1, CUB-2, CUB-3, CUB-4, CUB-5, CUB-6, CUB-7, CUB-8, CUB-9, CUB-10, CUB-11, CUB-12, CUB-13, CUB-14, CUB-15, CUB-16; Coppola 4 Tr 5460-99, Exhibits AG-32, AG-33, AG-34, AG-35, AG-36, AG-37, AG-38, AG-39, AG-40, AG-41, AG-42, AG-43, AG-44, AG-45, AG-46.

A utility's cost of common equity is the expected return that investors require on an investment in the utility. (Walters 3 Tr 1463.) Investors expect to earn their required return by receiving dividends and through stock price appreciation. (*Id.*) Consistent with the general financial and economic standards set forth in *Bluefield Water Works & Improvement Co v Pub Serv Comm'n of W Va*, 262 US 679 (1923) and *Fed Power Comm'n v Hope Natural Gas Co*, 320 US 591 (1944) a utility's ROE should be sufficient to maintain financial integrity, attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk. Considering the current and projected state of the utility industry, the Company's overall risk profile, and the results of several analytical methods which ABATE witness Christopher Walters analyzed for this case, the Company's ROE should be set at no higher than 9.40%.

1. The utility industry's access to capital and the context of the current economic environment indicate the Company's ROE should be reduced.

The Company requests a 10.25% ROE. (Walters 3 Tr 1530.) Because this proposal is inconsistent with utility industry trends, access to capital, and the Company's credit strength, it should be rejected.

While the Company recommended an increase above its current ROE, authorized ROEs for regulated utilities have generally declined since 2009 and have remained below 10.0% for more

than a decade (indeed, the majority of authorized ROEs have been below 9.7% since 2016, with many being below 9.5%).³ (Walters 3 Tr 1435-36.) During that time the utility industry's common equity ratios have not deviated much from the range of 50.0% to 52.0%. (Walters 3 Tr 1437.)

Moreover, utilities have enjoyed robust access to capital markets under favorable terms and costs. (Walters 3 Tr 1438.) This access to capital reflects the returns that regulatory commissions have found to be fair and reasonable. (*Id.*) In a 2026 Utility Capital Expenditures report, the Regulatory Research Associates (“RRA”) noted that “[p]rojected 2025 capital expenditure (“capex”) for 47 investor-owned energy utilities tracked by RRA stands at \$214.293 billion. . . a nearly 50% increase compared to the \$146 billion invested in 2022[,]” and demonstrating that capital investments continue to stay at elevated levels. (Walters 3 Tr 1438-40.) This increase in capital investment is enhancing shareholder value and attracting both equity and debt capital to the utility industry. At the same time, while capital markets embrace an increase in capital investments, regulatory commissions must protect customers and ensure service is reliable and rates are reasonable, affordable, and fair. (See *Id.*) Indeed, ignoring the impact of high rates on customers of all classes conversely results in revenue constraints for utilities which impact their financial integrity.

In conjunction with these increased investments, regulated utility equity securities continue to receive robust valuations, indicating that utilities can sell securities at high prices and access equity capital under reasonable terms and conditions at a relatively low cost. (Walters 3 Tr 1441.)

³ The Commission has stated that “the fact that other utilities have been able to access capital using lower ROEs, as argued by many intervenors, is a relevant consideration.” MPSC Case No. U-18255, 4/18/2018 Order, p 20; see also MPSC Case No. U-20561, 5/8/2020 Order, p 113 (explaining its decision and noting that the intervenors “showed that ROEs—both nationwide and in the Midwest—are trending downward with averages below that in Michigan, without harming the ability of affected utilities to access capital and attract investors”).

Utility security valuations are currently very strong and robust relative to the last several years, meaning utilities have access to equity capital under reasonable terms and at lower costs. (*Id.*; Exhibit AB-11.) Therefore, given that authorized returns on equity, credit standing, and access to capital have all been robust for utilities over the last several years, it is critical that the Commission ensure utility rates are increased no more than is required to provide fair compensation and maintain adequate financial integrity. See *Hope, supra*, 320 US at 591, 603.

The utility industry's relatively strong financial position is further buttressed by the Federal Reserve's (the "Fed") efforts to support the economy to achieve maximum employment and manage stable inflation at around a 2% level. (Walters 3 Tr 1444.) Specifically, the Fed has implemented procedures to support the economy's efforts to achieve these policy objectives, including reducing the federal funds rate to a range of 3.50%-3.75%. (Walters 3 Tr 1445.) Meanwhile, the yield spread between utility bonds and Treasury bonds has narrowed and is currently below its long-term average, which indicates that investors perceive lower relative risk in utility bonds. (Walters 3 Tr 1446.) And in a December 10, 2025 statement, the Fed suggests that economic activity is expanding at a moderate pace, but job gains have slowed and inflation remains somewhat elevated. (Walters 3 Tr 1446-47).

With respect to interest rates, the outlook for interest rates has moderated more recently relative to 2020 and part of 2021, when near-term projections for 30-year Treasury yields ranged from 1.9% to 2.8%. (Walters 3 Tr 1450.) Most recently, actual interest rates were approximately 4.5%, with near and intermediate projections in the range of 4.2% to 4.3%. While interest rates were expected to increase drastically from their actual levels in the 2020-2021 period, those same projections are now flat to declining, which indicates the cost of long-term capital might be near its peak. (*Id.*)

While the interest rate outlook is favorable for utilities, credit rating agencies' analyses have stressed that rate affordability is an important consideration in assessing utility credit. (Walters 3 Tr 1457.) According to S&P Global Market Intelligence, U.S. investor-owned energy utilities requested rate increases totaling \$22.06 billion in 2025, which represents the highest annual total of electric and gas rate increase requests since RRA began tracking rate case proceedings in the early 1980s. (Walters 3 Tr 1458.) Electric utilities accounted for \$18.23 billion of the total, driven by significant capital expenditure plans for upgrading transmission and distribution systems, installing new generation, and accommodating growing demand from data centers and other large loads. (*Id.*) RRA also observed that affordability has shifted from "a background concern to a binding constraint on what utilities can earn and build" noting that energy prices have risen faster than inflation and that customer dissatisfaction is at historic highs. (*Id.*) S&P and Fitch have also identified rate affordability as a key credit risk for the industry. (Walters 3 Tr 1459.)

Indeed, rate affordability is directly relevant because the authorized ROE is one of the single largest components of the cost of equity capital that is recovered from ratepayers, and it is the component over which the Commission exercises direct control. Every basis point of authorized ROE translates into higher rates for customers. (Walters 3 Tr 1460.) Therefore, considering the relative strength of the utility industry's financial position in the immediate and long-term it is inappropriate and unnecessary to increase the Company's ROE, especially to such a dramatically elevated level of 10.25%. It is instead imperative that utility rates reflect the relative stability of utility performance contrasted with the impact of increasing rates on customers of all classes. The Company's proposed increase in its ROE should therefore be rejected and the Commission should instead approve a ROE of no higher than 9.40%.

2. The Company's risk indicates it is a safe, stable investment

The Company's level of risk is generally described by credit rating analysts' reports (Walters 3 Tr 1466.) The current credit ratings for DTE Electric are A- from S&P and A2 from Moody's, and its outlook from S&P is "Stable" and Moody's is "Negative." (*Id.*) (citation omitted).

Further, S&P noted in its March 10, 2026 report that the MPSC recently "issued an order on DTEE's rate case, approving an approximate \$258 million (including \$16 million of IRM rolled into base rates) rate increase . . . [which] generally supports credit quality." (*Id.*) Moreover, the report concluded that DTE Electric's risk profile "reflects the very low risk of the regulated utility business, operations under a credit-supportive regulatory environment in Michigan, effective management of regulatory risk, and large customer base of 2.3 million customers in Michigan." (Walters 3 Tr 1467.) As clearly stated by S&P, DTE Electric has a strong credit profile and ratings, low risk, and benefits from constructive credit support mechanisms and Michigan's existing regulatory framework. (*Id.*) This provides a clear framework for lowering the Company's ROE when its risk profile diminishes. As evidenced above, DTE's persistent overearning and revenue sufficiencies demonstrate the Company's lower risk and justify a lower ROE. (Dauphinais 3 Tr 1299.) For instance, the Company's ability to consistently overearn and utilize a projected test year for establishing its revenue requirement reflect a revenue model with little volatility or uncertainty. DTE's earnings exceeded its authorized return in several of its last historical test years, indicating that it operated under conditions of reduced financial risk. (*Id.*) The recovery certainty and derisking is therefore readily apparent here through the mechanisms that provide DTE stable cost recovery and over-forecasted revenues. These realities should be considered when evaluating whether an ROE reduction is warranted.

Again, DTE's authorized ROE should reflect its actual risk and evolve with its risk profile. The regulatory mechanisms available to the Company clearly insulate it from risk and permit it to

earn above its authorized ROE. As ABATE witness Walters describes: “A company that is actively seeking to shed risk on two fronts, and that is rated three notches above the average of the group from which its cost of equity is estimated, is not a company whose risk profile supports a return above what those models indicate.” (Walters 3 Tr 1475.) This is particularly the case here, where the Company’s persistent revenue sufficiencies resulting from projected test year costs indicate DTE is systematically overprojecting its costs or underestimating its revenues. (Dauphinais 3 Tr 1299.) Basing the Company’s revenue on a historical test year would more accurately reflect the utility’s actual earnings and mitigate inflated revenue requirements, although given the above and the analyses below, the Company does not require a ROE above 9.40%.

3. The Company’s proposed capital structure is unreasonable, contradicts the Commission’s preferences, and skews its ROE request.

The Company’s proposed 51.50% equity ratio is higher than the 50.0% equity ratio the Commission authorized in the Company’s last rate case, counter to the Commission’s directives on this topic, and well above the equity ratios of the proxy companies used to estimate its cost of equity. (See Walters 3 Tr 1515-16, 1529.) The Commission should therefore reduce the Company’s equity ratio to avoid unnecessarily increasing customer rates. (*Id.*)

The Company relies on Moody’s March 2026 revision of its outlook from “stable” to “negative” to support a higher equity ratio. (Walters 3 Tr 1516; Lepczyk 4 Tr 4674.) The outlook revision does not support the Company’s proposal. Moody’s did not downgrade DTE Electric; it affirmed every one of the Company’s ratings, including its A2 Issuer Rating. (Walters 3 Tr 1516-17.) And the rationale Moody’s gave is specific; it is not about authorized returns or capital structure. Moody’s attributed the outlook change to the pressure DTE Electric’s financial profile will face during an elevated capital investment cycle, describing a program of approximately \$30 billion over 2026 through 2030 driven by the clean energy transition and load growth. The metric

at issue is the ratio of Cash Flow from Operations Before Changes in Working Capital (“CFO pre-WC”) to debt, which Moody’s expects to remain in the 18% to 20% range against its 21% downgrade threshold. Moody’s attributes the decline in that ratio to the growing capital investment program and the mismatched timing of commodity cost recovery. It does not attribute the decline to insufficient authorized returns. (Walters 3 Tr 1517.)

Moody’s own Credit Opinion, which the Company produced in discovery, confirms the point. Moody’s grades the sufficiency of DTE’s rates and returns at A, and the consistency and predictability of Michigan regulation and the timeliness of cost recovery at Aa, both currently and on its forward-looking view. (Walters 3 Tr 1517-18.) Moody’s projects no deterioration in any regulatory factor, and it projects that DTE’s debt to capitalization will remain in a range of 46% to 50% that brackets its current level. (Walters 3 Tr 1518-19.) In short, Moody’s identified a cash flow condition, not a capitalization problem, and nothing in its report calls for a thicker equity layer. (Walters 3 Tr 1519-20.) DTE Gas confirms that conclusion. It operates under the same Commission, the same regulatory framework, and the same 50% authorized equity ratio, and Moody’s affirmed its A3 rating with a stable outlook. (Walters 3 Tr 1520.) The variable that distinguishes the two utilities is the size of DTE Electric’s capital program, not its authorized capital structure. (Walters 3 Tr 1521.)

The Company’s proposed remedy also does little to improve the metric Moody’s flagged. While DTE argued that a thicker equity layer improves the Company’s cash flow to debt ratio, shifting 1.5 percentage points of DTE’s capitalization from debt to equity would improve that ratio by only about one-half of a percentage point, while DTE Electric’s 2025 dividend to its parent consumed 5.7 percentage points of the same ratio. ((Lepczyk 4 Tr 4674; Walters 3 Tr 1521-23.) From 2021 through 2025, DTE paid \$3.975 billion in dividends to DTE Energy, approximately

\$475 million more than the \$3.5 billion of equity the parent contributed. (Walters 3 Tr 1521.) DTE also holds a conditional commitment for up to \$7.2 billion of low-cost federal loans, plans further securitization, and expects to transfer \$547.1 million of tax credits during the test period, all of which improve cash flow coverage without asking customers to fund a richer capital structure. (Walters 3 Tr 1524.) Of the levers available, the Company selected the smallest and the only one customers pay for. (Walters 3 Tr 1523.)

Moreover, DTE's proposal conflicts with the Commission's clear directives on capital structures. In DTE's last general rate case, Case No. U-21860, the Commission found "the ALJ's recommendation to maintain a balanced capital structure comprised of 50% debt and 50% equity to be well-reasoned and supported by the record." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered February 19, 2026 (Case No. U-21860), p 276. In Consumers Energy's recent electric rate case, the Commission likewise found "that the balanced capital structure most appropriately balances the interests of the utility's investors and customers, consistent with the holdings in Bluefield and Hope." *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered March 21, 2025 (Case No. U-21585), p 233. The Company's requested 51.50% equity ratio moves in the opposite direction from the Commission's consistently stated preference. For several rate case cycles the Commission has authorized a 50% equity ratio for the major utilities it regulates, including DTE Electric, DTE Gas, and both Consumers Energy operating divisions. Indeed, that policy has not impaired Michigan utilities' access to capital. (Walters 3 Tr 1523.) DTE Electric is rated A2 and DTE Gas A3, both while operating under a 50% authorized equity ratio, and Moody's grades the consistency and predictability of Michigan regulation in the double-A category. (*Id.*) The Commission should not be swayed by Moody's March 2026 outlook.

The proposal is also costly to customers and mismatched to the cost of equity evidence. Moving from a 50/50 structure to the proposed 48.50%/51.50% structure raises the pre-tax weighted average cost of capital by approximately 12 basis points applied to the entire rate base, and the Company's combined request (a 51.50% equity ratio and a 10.25% ROE) exceeds a 50/50 structure with a 9.40% ROE by approximately 56 basis points. (Walters 3 Tr 1526.) Further, the proxy companies from which the cost of equity is estimated carry average equity ratios of 38.4% (including short-term debt) and 41.9% (excluding short-term debt). Applying a cost of equity derived from companies with roughly 40% equity to a 51.50% equity ratio would overcompensate the utility. (Walters 3 Tr 1527-29.)

The Company's proposed 51.50% equity ratio directly contradicts the Commission's preference for the Company to maintain a more balanced capital structure (*i.e.*, 50/50) and circumstances do not warrant a deviation from this equity ratio here. (Walters 3 Tr 1529.) Staff, the Attorney General, and CUB likewise recommend a 50% equity ratio; the Company stands alone in seeking a higher one. (Lepczyk 4 Tr 4674.)

4. The Company's proxy group demonstrates a lower ROE is reasonable.

An appropriate proxy group is necessary to determine a reasonable return by considering investments in other firms of comparable risk. (Walters 3 Tr 1476.) The proxy group utilized for ABATE's quantitative analyses is the same group developed by the Company, minus Dominion Energy, Inc. and NextEra Energy, Inc. due to the announced transaction between the two companies. (Walters 3 Tr 1476–77). Additionally, ABATE witness Walters removed Portland General Electric Company due to its announced deal to acquire three power plants from PacifiCorp for \$1.9 billion, or 32.5% of Portland General Electric Company's market capitalization value. These transactions fundamentally alter the companies' financing and investment fundamentals and are therefore not appropriate for use as proxies in this case. (Walters 3 Tr 1477).

The proxy group developed by ABATE has average credit ratings of BBB+ and Baa2 from S&P and Moody's, respectively. (*Id.*) The BBB+ rating from S&P is one notch lower than DTE Electric's rating of A- from S&P and the Baa2 rating from Moody's is three notches lower than DTE Electric's rating of A2 from Moody's. (*Id.*) Similarly, the proxy group has an average common equity ratio of 38.4% (including short-term debt) and 41.9% (excluding short-term debt) as calculated by *S&P Global Market Intelligence* and *Value Line*, respectively. Although DTE's credit ratings are superior to those of the proxy group, the Company's requested equity ratio of 51.50% significantly exceeds the proxy group's equity ratio of 38.4%. (*Id.*) Therefore, DTE is less risky than the proxy group from which its cost of equity is estimated, and a cost of equity drawn from companies with equity ratios near 40% should not be paired with a 51.50% equity ratio. (Walters 3 Tr 1527-29.)

5. Reasonable empirical models demonstrate a reasonable ROE for the Company is 9.40%

In developing a reasonable ROE for the Company, ABATE witness Walters applied the following empirical models to the proxy group described above: (i) a constant growth discounted cash flow ("DCF") model using the consensus of analysts' growth rate projections; (ii) a constant growth DCF using sustainable growth rate estimates; (iii) a multi-stage growth DCF model; (iv) a risk premium model; and (v) a capital asset pricing model ("CAPM"). Considering the results of these analyses, and DTE's specific risk profile, a reasonable ROE is 9.40%. (Walters 3 Tr 1464, 1511.)

a. Constant growth DCF model.

The constant growth DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. (See Walters 3 Tr 1478.) ABATE's constant growth DCF model relied on the average of

the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on July 24, 2026. (*Id.*) An average stock price is less susceptible to market price variations than a price at a single point in time, meaning an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value. (Walters 3 Tr 1478–79.)

ABATE used each proxy company's most recently paid quarterly dividend as reported in *Value Line*. (Walters 3 Tr 1479.) For dividend growth rates, to attempt to estimate investors' expectations about what the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to make individual investment decisions, securities analysts' growth estimates that are captured in observable stock prices have been shown to be more accurate than growth rates derived from historical data. (*Id.*) Therefore, ABATE relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. (Walters 3 Tr 1480.) The specific growth rates used are shown in Exhibit AB-13. The average growth rate for the proxy group is 8.15% and the median growth rate is 7.92%. As shown in Exhibit AB-14, the average and median constant growth DCF returns for the proxy group for the 13-week analysis are 11.60% and 11.24%, respectively. (Walters 3 Tr 1480.)

It should be noted, however, that the proxy group average three- to five-year growth rates are approximately 104% higher than the long-term projected GDP growth rate of 3.99%.⁴ (Walters 3 Tr 1481.) This makes these ROE estimates much higher than is reasonable as a utility's growth

⁴ Blue Chip Economic Indicators projects a U.S. nominal GDP growth rate of 3.99% over the next 10 years. (Walters 3 Tr 1481). This is a reasonable proxy of long-term growth because utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services and can be used as a conservative maximum long-term growth rate projection (*Id.*)

rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the DCF model. (*Id.*)

b. Sustainable growth DCF model.

The sustainable growth rate is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment, which reinvested earnings enhance the earnings base (also known as rate base). (Walters 3 Tr 1482.) The internal growth approach is linked to the percentage of earnings retained within the Company, as opposed to being paid out as dividends. (*Id.*) The payout ratios of the proxy group are shown in Exhibit AB-15. These dividend payout ratios and earnings retention ratios can be used to develop a long-term growth rate driven by earnings retention. (*Id.*) The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. (*Id.*) As shown in Exhibit AB-16, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 5.96% and 5.88%, respectively. A DCF estimate based on these sustainable growth rates is developed in Exhibit AB-17 and produces proxy group average and median DCF results for the 13-week period of 9.35% and 8.96%, respectively. (Walters 3 Tr 1483.)

c. Multi-Stage growth DCF model.

The DCF model is intended to represent the present value of an endless series of future cash flows. (Walters 3 Tr 1483.) In addition to the analyses described above, to accommodate changing growth expectations over time as investments slow or plateau, it is therefore also important to consider a multi-stage DCF analysis that reflects growth rate change over time. (*Id.*) In other words, the three- to five-year growth rate projection noted above should be viewed as a long-term sustainable growth rate, but not without considering current market conditions and

industry trends, and determining whether the three- to five-year growth outlook is feasible and sustainable. (Walters 3 Tr 1483–1484.)

The multi-stage DCF model reflects the possibility of non-constant growth for a company over time and reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity. (Walters 3 Tr 1484.) Again, utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which these utilities sell services. (Walters 3 Tr 1485.) As such, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. (*Id.*) Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

As shown in Exhibit AB-18, the average and median DCF ROEs for the proxy group using the 13-week average stock price are 8.27% and 8.22%, respectively. (Walters 3 Tr 1488) Again, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 8.15%, which is approximately 104% higher than the long-term projected GDP growth rate of 3.99%. (*Id.*) As this is an unsustainable assumption it likely leads to an overstatement in the cost of equity for a low risk regulated utility. As such, more weight should be given to the sustainable growth and multi-stage models of the DCF.

d. Risk premium model.

This model is based on the principle that investors require a higher return to assume greater risk. (Walters 3 Tr 1489.) This risk premium model is based on two estimates of an equity risk premium: (i) the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds; and (ii) the difference between regulatory commission-

authorized returns on common equity and contemporary “A” rated utility bond yields by Moody’s for certain relevant periods. (*Id.*)

Over the period studied, the ERP over U.S. Treasury bonds averaged 5.68%. (Walters 3 Tr 1490.) Five-year rolling averages ranged from 4.25% to 7.10%, while the ten-year rolling average Risk Premium ranged from 4.38% to 6.91%, as shown in Exhibit AB-20. The ERP over “A”-rated utility bonds averaged 4.34% over the same period, with five-year rolling averages ranging from 2.88% to 5.91% and ten-year rolling averages ranging from 3.19% to 5.74%, as shown in Exhibit AB-21. (*Id.*)

In Exhibit AB-22, ABATE witness Walters also examined the yield spread between utility bonds and Treasury bonds since 1980. (*Id.*) Historically, “A”-rated utility bonds have yielded 1.45% more than Treasury bonds, while “Baa”-rated utility bonds have yielded 1.86% more. Currently, the yield on “A”-rated utility bonds is 5.83% compared to 4.96% for long-term Treasuries, a spread of 0.87%. The yield on “Baa”-rated utility bonds is 6.00%, a spread of 1.04%. Both current spreads are below their respective long-term averages, which indicates that investors presently view utilities as less risky than in the past. (*Id.*) Bond spreads are a real-time, market-based measure of investor risk perceptions, and provide valuable input for setting a just and reasonable ROE. Maintaining an elevated ROE when market evidence shows reduced risk would overcompensate utilities and unnecessarily increase rates for consumers. (Walters 3 Tr 1491.)

Taking the risk premium result from the method described above, including an ERP of 5.33% over Treasury bonds to Blue Chip’s projected 30-year Treasury yield of 4.80% produces an ROE of 10.13%. (*Id.*) (internal citation omitted). Adding an ERP of 4.14% over “A”-rated utility bond yields to the recent three-month average “A”-rated utility bond yield of 5.83% results in a 9.97% ROE (Walters 3 Tr 1491–92.) With six-month average yields, the ROE is reduced to 9.90%.

(Walters 3 Tr 1500.) Finally, as described by ABATE witness Walters, using a weighted least squares regression (“WLS”) analysis, the ROE is reduced even further to 9.88%. (Walters 3 Tr 1499.)

e. CAPM model.

The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. (Walters 3 Tr 1500.) In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations. (*Id.*)

Non-diversifiable risks, on the other hand, are related to market conditions and are referred to as systematic risks. (*Id.*) These risks cannot be reduced through diversification and are considered market risks. Conversely, as indicated above, non-systematic risks, also known as business risks, can be reduced through diversification. (Walters 3 Tr 1500–01.) According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. (Walters 3 Tr 1501.) Investors are only compensated for taking on systematic, or non-diversifiable, risks. (*Id.*)

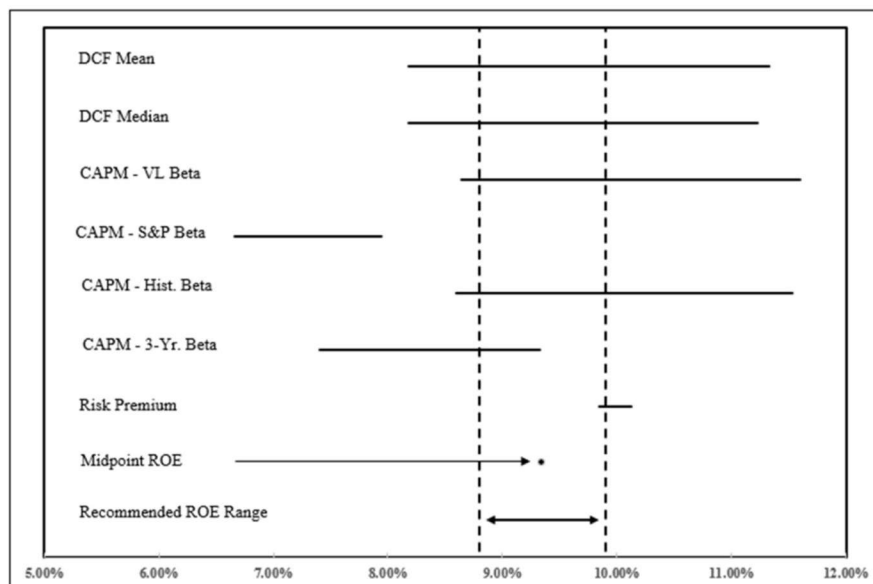
The CAPM requires an estimate of the market risk-free rate, the Company’s “beta” (which is a measure of systematic risks), and the market risk premium. (*Id.*) The market risk premium is the difference between the expected market return and the risk-free rate. ABATE’s analysis considered four beta estimates: the proxy group’s current Value Line betas (average 0.73), the long-term average of the proxy group’s Value Line betas (0.78), three-year betas adjusted using Value Line’s methodology (0.49), and Vasicek-adjusted betas from S&P Global Market Intelligence’s Beta Generator Model (0.33), which rely on five years of weekly data ending July 24, 2026.

(Walters 3 Tr 1501-02; Exhibit AB-25.) Market Intelligence betas as calculated using its Beta Generator Model are adjusted using the Vasicek method and calculated using the S&P 500 as the proxy for the investable market. (Walters 3 Tr 1502.) Because the analysis relied on the S&P 500 to estimate the expected return on the investable market, it is consistent to rely on beta estimates that are also calculated using the S&P 500 as the benchmark for the market. As shown in Exhibit AB-26, the results of twelve (12) different applications of the CAPM range from 6.66% to 12.06%. (Walters 3 Tr 1509-10.)

6. A reasonable ROE for the Company should be no higher than 9.40%.

Based on these analyses, an appropriate estimate for the Company's current market cost of equity is within the reasonable range of 8.90% to 9.90% (Walters 3 Tr 1511.) This recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model and gives more weight to the sustainable growth and multi-stage models of the DCF. (*Id.*) Figure CCW-9 summarizes the results of each model:

FIGURE CCW-9



Therefore, based on an objective assessment of DTE's overall risk profile and the results of these analytical methods, an appropriate ROE for the Company is 9.40%, which is the midpoint of the range produced by these models. (Walters 3 Tr 1511.) Adopting an ROE of 9.40% and a common equity ratio of 50.0% would reduce DTE's claimed revenue deficiency by approximately \$145.1 million. (Walters 3 Tr 1432; Dauphinais 3 Tr 1290-93.) Indeed, DTE belongs in the lower half of ABATE's recommended range of 8.90% to 9.90% for several reasons. First, DTE Electric is rated A2 by Moody's and A- by S&P, three notches and one notch respectively above the proxy group averages of Baa2 and BBB+. Second, the Company requests a common equity ratio of 51.50%, well above the proxy group average of 38.4% (including short-term debt) and 41.9% (excluding short-term debt), which further reduces the risk borne by its equity holders. Third, the Company proposes in this proceeding to shed the sales forecast risk associated with the largest single load addition on its system. Fourth, an increasing share of the Company's distribution investment is recovered through its IRM surcharge rather than through base rates, which reduces both the regulatory lag and the spend level exposure borne on that investment.

Each of these indicates that DTE Electric is less risky than the average company in the group from which its cost of equity is estimated, and such a reduction in risk would warrant an ROE in the lower half of ABATE's indicated range, (i.e. 8.90% to 9.40%). ABATE's recommendation of the midpoint is conservative in that respect, and the record in this proceeding would well support the Commission authorizing a return below 9.40%. (Walters 3 Tr 1511-12.) ABATE does not propose that the Commission quantify these risk-reducing mechanisms as a discrete basis point adjustment, and does not propose a different authorized rate of return on investment recovered through the IRM than on investment recovered through base rates; the cost

of equity estimated above is derived from companies that themselves recover their costs through a mix of base rates and rider mechanisms, and already reflects that blend. (Walters 3 Tr 1475.)

DTE's response that its riders merely make it comparable to the proxy group misses the point. (See Nelson 4 Tr 2689-90.) ABATE does not contend that DTE's cost recovery mechanisms, standing alone, distinguish it from the proxy companies; fuel clauses and infrastructure riders are common across the industry. (Walters 3 Tr 1469.) What distinguishes this case is the LLTM, which DTE proposes here to remove the sales forecast risk of a 1.4 GW load addition from its test year results, and DTE's request to expand the IRM from the \$282.5 million authorized for 2027 to \$795.0 million by 2030. (Walters 3 Tr 1470-71, 1474.) The Company cannot present the LLTM as a customer protection while asking to be compensated as though it continued to bear the forecast risk the mechanism removes. (Walters 3 Tr 1472.)

7. The Company's requested ROE is excessive and unreasonable.

The Company recommends a return on common equity range of 9.95% to 11.80% with a recommended ROE of 10.25%. (Walters 3 Tr 1530.) It arrived at these percentages based on its analyses of several models. Those models included a traditional CAPM and an empirical CAPM ("ECAPM"), a constant growth and quarterly growth DCF models, and a bond yield plus risk premium ("BYRP") analysis. (*Id.*) As shown below, however, the Company's models use unreasonable inputs which lead to inflated results and a higher ROE. Specifically, DTE's estimated ROE is the result of the following flaws: (1) its constant growth DCF results are based on unsustainably high growth rates; (2) its CAPM and ECAPM are based on inflated market risk premiums, adjusted beta estimates, and flawed methodology; and (3) its BYRP model is predicated on an excessive estimated ERP. (Walters 3 Tr 1532.) As this proposal is excessive and unreasonable given DTE's actual risk and the flaws in the Company's analyses, the Commission should reject the Company's request.

a. The Company's DCF model analyses are flawed and overstated.

The Company conducted a Constant Growth DCF analysis using average stock prices over 30, 90, and 180 trading days, and annualized dividend per share data, and applied the quarterly compounding method of the constant growth DCF model. (Walters 3 Tr 1532). This resulted in an average DCF range from 9.59% to 11.66% and an average DCF range using the quarterly compounding method from 9.78% to 11.92%. (Walters 3 Tr 1533.); see also (Schedule D5.2–D5.3). As ABATE witness Walters points out, these growth rates exceed projected GDP growth and are therefore unreliable. (Walters 3 Tr 1533–34.) DTE's proxy group average growth rate of 7.05% is approximately 77% higher than the 3.99% projected long-term nominal GDP growth rate, and its individual company growth rates run as high as 8.28%. (*Id.*) Growth rates that exceed the growth rate of GDP in the country in which a utility provides goods and services cannot be sustained. (Walters 3 Tr 1534.) DTE failed to consider the results of a multi-stage DCF which would have accounted for the expected growth of the U.S. economy. (*Id.*)

As demonstrated by ABATE witness Walters, the average and median results of a multi-stage DCF model are 8.27% and 8.22% with a midpoint of 8.25%. (Walters 3 Tr 1534.) Taking the average of 8.25% with the average of the Company's low- and mean-growth constant growth DCF results of 10.16%, 10.11%, and 10.19% would produce more reasonable composite DCF results in the range of 9.18% to 9.22%. (Walters 3 Tr 1535.) Therefore, after considering the multi-stage model, and removing the highly inflated (and unreasonable) high growth rate in the Company's DCF model, a DCF-based ROE closer to 9.20% is reasonable, if not generous. (*Id.*)

b. The Company's CAPM analysis relies on inflated market risk premiums.

DTE relies on a proxy group average beta estimate of approximately 0.68 based on the average beta from *Value Line* and *Bloomberg*; and an average ten-year *Bloomberg* beta estimate

of approximately 0.76. (Walters 3 Tr 1535.) The Company also relied on a market risk premium in the range of 7.40% to 11.70%, a current risk-free rate of 4.83%, and the average of the near-term and long term projected risk-free rate of 4.68%. (*Id.*) This produced a CAPM return in the range of 9.77% to 13.49%. (*Id.*) (citing Schedule D5.5). There are two issues with the Company's approach. *First*, the market risk premiums based on the Company's DCF-derived expected market returns are significantly overstated and do not reflect a reasonable estimate of the expected return, including a growth rate of 15.14% or 3.8x the long-term growth rate outlook for U.S. GDP, which is 3.99%. (Walters 3 Tr 1536–37.) *Second*, the Company fails to incorporate the MRP recommended by Kroll, which is one of the most trusted and widely used sources for estimating cost of capital parameters. (Walters 3 Tr 1538.) By this omission, the Company overstates the MRP and, in turn, the cost of equity in its CAPM results. (Walters 3 Tr 1539.) Applying Kroll's normalized 5.00% MRP and 5.00% risk-free rate to the Company's own beta estimates produces CAPM results of 8.38% and 8.78%, and averaging that midpoint with the Company's historical market return CAPM results produces a revised CAPM estimate of 9.33%. (*Id.*)

c. The Company's ECAPM analysis is inherently flawed, inflated, and should be rejected.

The Company's ECAPM should also be rejected. The ECAPM analysis was originally designed to use unadjusted regression betas, yet the Company utilized an adjusted beta as published by *Value Line*. (Walters 3 Tr 1540.) This inevitably inflated the Company's proxy group's average beta estimate range from 0.676 and 0.756 to effective betas of 0.757 and 0.817, respectively.⁵ (Walters 3 Tr 1541.) The end result of using adjusted betas in the ECAPM is an

⁵ Regulatory commissions across the country generally disfavor the use of ECAPM, particularly when an adjusted beta is used in the model. For instance, the California Public Utilities Commission concluded that “[w]e are not persuaded that ECAPM produces a result that should be

expected return that has been flattened by *two* adjustments, meaning the vertical intercept has been raised twice and the security market line has been flattened twice. (*Id.*) As described by ABATE witness Walters, there is simply no legitimate basis to use an adjusted beta within an ECAPM because it unjustifiably inflates a CAPM return for a company with a beta less than one (1), such as DTE. (Walters 3 Tr 1542-43.) Across the eight pairings of inputs the Company presents, its ECAPM raises the indicated cost of equity by 46 to 95 basis points relative to the traditional CAPM. (Walters 3 Tr 1541.) This Commission has also already rejected DTE's use of the ECAPM, adopting the ALJ's finding in Case No. U-21860 that the ECAPM is "an approach that this Commission, like most commissions, has rejected." (Walters 3 Tr 1544-45.) Therefore, the Commission should reject the Company's proposed ECAPM and not consider it when determining an appropriate ROE range.

d. The Company's bond yield risk premium analysis and associated regression study is flawed.

The Company's BYRP model produced an estimated cost of equity of 10.36% when using the current 30-year Treasury yield of 4.83%, and 10.28% when using the projected 30-year Treasury yield of 4.68%. The Company's regression has an R-squared of 0.7653, meaning that approximately 77% of the variation in the ERP is explained by Treasury yields within the model, and approximately 23% is left unexplained. (Walters 3 Tr 1547.) As ABATE witness Walters explains, the fundamental flaw in the Company's model is that it assigns equal weight to every observation in its dataset, regardless of when it occurred. (*Id.*) In particular, the dataset spans 46 years and includes rate cases decided during the 1980s, a decade characterized by historically anomalous double-digit Treasury yields. The 30-year Treasury yield averaged 11.35% during the

considered . . . [a]djusting betas upward *guarantees* a higher return on equity." (Walters 3 Tr 1545.) (emphasis added) (internal citations omitted).

1980s, compared to 4.83% in the Company's analysis. The authorized ROE in that same decade averaged 14.80%. (Walters 3 Tr 1547.) In practice, the Company's model fits the distant past almost perfectly. For the 727 cases decided in the 1980s, the Company's model's average prediction is within 3 basis points of the average ROE actually authorized. For the 1990s it is within 4 basis points, and for the 2010s it is within 4 basis points. Its performance in the current period is entirely different. From 2020 through 2026, the Company's model over-predicts the average authorized ROE by 38 basis points, and the bias is one-directional. The Company's model over-predicts in every single year from 2020 forward: by 46 basis points in 2020, 35 basis points in 2021, 17 basis points in 2022, 31 basis points in 2023, 38 basis points in 2024, and 55 basis points in 2025. (Walters 3 Tr 1550.) ABATE re-estimated the Company's exact regression, using the identical semi-logarithmic functional form, the Company's identical dataset, and identical estimation procedure, restricted to more recent sub-periods. The results are as follows, evaluated at the Company's projected 30-year Treasury yield of 4.68%:

- Full sample, 1980 through 2026 (the Company's result): 10.28%.
- Cases since 2010: 10.20%.
- Cases since 2015: 9.98%.
- Cases since 2020: 9.90%.

The pattern is clear. The more the sample is restricted to the regulatory and capital market environment that actually prevails today, the lower the indicated cost of equity. (Walters 3 Tr 1551.) Applying the Company's own model to the last decade of authorized returns reduces the result by approximately 30 basis points, and applying it to the period since 2020 reduces it by approximately 38 basis points. No change in methodology is required to reach that outcome; only a recognition that a rate case decided in 1982 does not inform the return investors require in 2026.

Notably, these figures bracket the 9.79% produced by correcting the weighting of DTE's data, and are consistent with the 9.88% indicated by ABATE's Risk Premium regression. (*Id.*) Therefore, correcting only the weighting of the Company's own data produces a cost of equity of 9.79%, well below the 10.28% to 10.36% range the Company reports. (Walters 3 Tr 1553.)

In sum, given these unreasonable inputs which inflate the Company's ROE range, the Commission should reject the Company's ROE recommendation and adopt the more reasonable and accurate ROE proposed by ABATE.

D. Other Revenue-Related Items.

1. Production O&M expense.

a. Inflation and DTE's lack of a productivity adjustment.

References in the Record: York 3 Tr 1367-71, Exhibit AB-8; Davis 3 Tr 1603, 1609-19, 1626, Exhibit A-13; Kryscynski 4 Tr 4481; Menghaney 4 Tr 5170-86, 5196-98, Exhibit CUB-32, CUB-41, CUB-42.

DTE applied a composite labor and material inflation adjustment factor of 2.9% for 2026, 3.0% for 2027, and 0.5% for the first two months of 2028 which, compounded, increase the 2025 adjusted historical amount by approximately 6.5%. (See York 3 Tr 1367-71.) As DTE did not include any offset for productivity these projected inflation factors are excessive.

DTE asserted that "[t]here was no explicit offset for workforce or operational productivity gains," and pointed to its testimony that "applying a productivity offset risks double counting productivity gains" and "broad external productivity indices do not directly correspond to the Company's regulated operations, collective bargaining framework, or service-quality obligations." (Exhibit AB-8 at 30; Davis 3 Tr 1603-04.) Alternatively, DTE claimed that its blended rate is conservative which is "similar to the effect of a downward productivity adjustment to inflation." (*Id.*) The Commission directly addressed this issue in its February 19, 2026 Order in Case No. U-21860, stating "it is unreasonable for the company to not assume an offset for workforce

productivity in its labor inflation projection.” The Commission also rejected DTE’s proposed blended inflation rates there, instead adopting Staff’s and agreeing that DTE’s proposed blended rate does “not include offsetting reductions to O&M based on efficiency gains that accompany experience.” The Commission made the same point in Case No. U-20697, stating that “the Commission has historically rejected the concept of a blended inflation rate” and citing to its previous May 8, 2020 Order in Case No. U-20561, where it held that “while DTE Electric will see some inflation, the company will also offset some of the inflation with productivity gains.” *In the Matter of the Application of Consumers Energy Co.*, order of the Public Service Commission, entered December 17, 2020 (Case No. U-20697), pp 171-72.

Despite this consistent direction from the Commission DTE included no productivity offset here and its gesture towards the equivalence of its conservative blended rate is inadequate. As ABATE witness York explained, the selection of an inflation index, even if it is conservative, “measures the change in the price of an input,” while a “productivity offset measures the change in the quantity of the input required to produce a unit of output.” (York 3 Tr 1367-71.) Workforce efficiency leading to fewer required labor hours for the same work is independent and not related to DTE’s wage rates. (*Id.*) DTE’s position is also contradictory. While DTE claimed that external productivity indices cannot be applied to DTE’s regulated operations, collective bargaining framework, or service-quality obligations, it simultaneously referenced the benefits of industry collaboration and best practice benchmarking to justify other elements of its requested revenue recovery. (See Guillaumin 4 Tr 3477-78 (describing benchmarking and best practices benefits obtained through industry association memberships).) DTE cannot argue that broad industry metrics are relevant for supporting revenue increases while disclaiming their utility when they would suggest inflation rate offsets.

DTE's own forecasting history also refutes its claim that its escalation methodology is already conservative. In discovery, DTE provided the total O&M expense it projected for 2023, 2024, and 2025 in its three preceding general rate cases, together with the adjusted O&M expense it now reports for those same years on the same Exhibit A-13, Schedule C5 basis. (York 3 Tr 1369-70; Exhibit AB-8 at 58-62.) DTE's projections exceeded the adjusted amounts in every year: by \$104.6 million (8.9%) for 2023, \$147.5 million (12.7%) for 2024, and \$170.0 million (15.5%) for 2025, a cumulative difference of \$422.1 million. (*Id.*) The gap widened in each successive case. (*Id.*) While a projected test year and an adjusted historical year are not identical constructs, the direction, magnitude, and persistence of the difference are the opposite of what a forecast that already anticipates productivity gains would produce, and cannot be reconciled with DTE's claim that an explicit offset would double count efficiency gains. (*Id.* at 1370.)

DTE's reference to BLS utility industry data on productivity also fails to demonstrate its own circumstances do not reflect productivity inflation offsets and does not engage with the Commission's explicit direction that such an offset be applied to DTE's inflation figures. (Davis 3 Tr 1612-19.) Indeed, as explained by CUB witness Menghaney, DTE's specific labor-related O&M costs and weather-normalized sales demonstrate "that the Company maintained relatively stable service levels while using fewer labor-related O&M dollars, demonstrating improved productivity over time." (4 Tr 5155.) Further, a productivity offset derived directly from Company-specific data, even "using DTE Electric's *least* efficient year over the last five years as a conservative benchmark results in a reduction of approximately 4% to the Company's total O&M forecast." (*Id.* at 5185.) DTE's assertion that there is no basis for any offset is therefore unreasonable.

As such the Commission should apply a 1% annual productivity offset to DTE's composite inflation factors for O&M. (York 3 Tr 1367-71.) This amount is conservative and is materially below the long-run rate of labor productivity growth in the United States business sector, and well below the 1.96% offset proposed by another party in Case No. U-21860. (*Id.*) As DTE applies its composite inflation factors to O&M expense generally, this productivity offset should also be applied to all of DTE's projected O&M expense. This adjustment is separate from, and not duplicative of, the distribution O&M adjustments sponsored by ABATE witness Fitzhenry. (York 3 Tr 1350-51.) This 1.0% annual offset would reduce DTE's proposed composite escalation factors from 2.9%, 3.0%, and 0.5% to 1.9%, 2.0%, and 0.32%, respectively. Compounded, the escalation applied to the 2025 adjusted historical base falls from approximately 6.5% to 4.3%. Applied to the \$1.097 billion adjusted 2025 historical O&M expense described above, the embedded inflation falls from \$52.326 million to \$34.815 million. (*Id.*) As such the Commission should adopt a reduction of \$17.512 million to projected test period O&M expense.⁶

b. Belle River coal-to-gas conversion.

References in the Record: York 3 Tr 1371-75, Exhibit AB-8; Guillaumin 4 Tr 3449, 3474-76, Exhibit A-13.

DTE projected \$22.1 million of Belle River O&M in the test period. (Guillaumin 4 Tr 3449, Exhibit A-13.) Because DTE's estimate of the O&M that will remain at Belle River after both units convert to natural gas is not adequately supported, the Commission should increase DTE's \$17.0 million O&M reduction by an additional \$1.55 million.

⁶ The recommended productivity offset should be applied regardless of the overall inflation factor the Commission adopts. If the Commission adopts lower gross inflation factors than DTE proposes the productivity offset should be applied to those factors. (York 3 Tr 1367-71.)

DTE developed its projected costs by escalating \$36.76 million of 2025 actual Belle River O&M costs to \$39.19 million using the inflation factors discussed above, and then applying retention percentages of 64.9% for labor, 0% for fuel, and exactly 50% for each of the remaining cost categories of Forced Outage, Operations, Maintenance, Admin, Performance, Instrument and Range. (*Id.*; York 3 Tr 1371-75.) ABATE does not challenge the labor retention, which DTE derived from projected headcount and 2025 labor rates. (York 3 Tr 1372.) However, DTE asserted this 50% figure “is an engineering judgement” which “reflects the expectation that, in aggregate, half of the historically incurred expense will continue and half will go away” and it “is not derived from a formula or discrete calculation.” (Exhibit AB-8 at 56.) When asked to provide a quantified apportionment of the \$17.0 million reduction between reduced plant utilization and elimination of coal-related equipment O&M, DTE stated that it “has not performed the analyses requested.” (*Id.* at 39.) Further, when asked to further explain this 50% figure DTE stated the estimate is “consistent with the approach used in the Company’s prior rate case (Case No. U-21860), which assumed a 25% reduction for one unit converting to natural gas.” (*Id.* at 56.) Thus, the Company’s “engineering judgment” underlying this estimate amounts to simply taking the 25% reduction it assumed for one unit and doubling it for two units. (York 3 Tr 1371-75.)

This approach is unreasonable and does not produce a reliable cost estimate. Specifically, the explanation of why the first unit conversion produced a limited reduction does not apply to the second. DTE acknowledged that it “is true that converting one unit did not obviate the need for the coal fuel handling equipment and labor serving the unconverted unit.” (Exhibit AB-8 at 46.) Thus, the reduction from converting Unit 1 was constrained by the need to keep the coal handling system in operation for Unit 2. (York 3 Tr 1371-75.) Converting Unit 2 removes that constraint and retires the coal handling system in its entirety, meaning the incremental reduction from the second

conversion should exceed the incremental reduction from the first. DTE's assumption that the two reductions are identical is unreasonable and unsupported. Indeed, DTE itself acknowledged that the "reduction projected for the conversion of Belle River Unit 2 is not directly proportionate to the reduction projected for the conversion of Belle River Unit 1." (Exhibit AB-8 at 52-53.)

DTE also projected that Belle River capacity factors will fall from 24% in 2026 to 14% in 2028 for Unit 1 and 58% in 2026 to 11% in 2028 for Unit 2. (Exhibit AB-8 at 55.) While DTE identified lower plant utilization as one of the two drivers of the \$17.0 million reduction, when asked to quantify any reduction to variable O&M attributable to lower run hours, DTE acknowledged that it "did not project O&M reductions down to the level requested." (Guillaumin 4 Tr 3449; Exhibit AB-8 at 47.) DTE also confirmed that Belle River will have fully discontinued coal-fired generation once the Unit 2 conversion outage begins in September 2026, approximately six months before the projected test period begins. (*Id.* at 29, 40.) DTE's projected test period therefore reflects two-unit natural gas operation at capacity factors in the range of 11% to 21%. These figures do not support the Company's assumed costs during that timeframe.

While DTE asserted it did not simply double the one-unit reduction because, in Case No. U-21860, DTE removed 25% of fuel handling labor expense, while in this case it removed 100% of fuel handling expense, that explanation concerns fuel handling, not the seven other cost categories to which DTE applied a uniform 50% retention and which are the subject of ABATE's adjustment. (York 3 Tr 1372; Exhibit AB-8 at 52-53; Guillaumin 4 Tr 3475.) DTE itself explained the 50% figure as "consistent with" the 25% reduction it assumed for one unit in Case No. U-21860. (Exhibit AB-8 at 56.) DTE offered no explanation of why Forced Outage, Operations, Maintenance, Admin, Performance, Instrument, and Range expense should fall by exactly half when coal handling is eliminated entirely and capacity factors fall to 11% to 14%. Instead DTE

stated only that the reduction was based on DTE's "decades-long experience operating and maintaining Belle River Power Plant and its engineering judgement." (Guillaumin 4 Tr 3476.) That is a restatement of the same unquantified judgment, not support for it.

Nor is DTE's criticism that ABATE's 40% retention lacks justification well taken. (*Id.*) DTE bears the burden of supporting its projection, and DTE's own 50% figure "is not derived from a formula or discrete calculation." (Exhibit AB-8 at 56.) ABATE asked DTE to quantify the effects of reduced utilization and the elimination of coal-related equipment, and DTE declined to perform that analysis. (*Id.* at 39, 47.) ABATE's 10 percentage point adjustment is a conservative response to record evidence DTE does not dispute: the removal of the coal-handling constraint and the steep projected decline in capacity factors. It is conservative because it does not separately quantify the effect of those lower capacity factors. (York 3 Tr 1374-75.)

DTE's cost projection here amounts to an unsupported judgment. (See Guillaumin 4 Tr 3476.) As such it has not met its burden to demonstrate the requested cost recovery is reasonable or prudent. Given the evidence on the record the Commission should instead approve a 40% retention percentage for Forced Outage, Operations, Maintenance, Admin, Performance, Instrument and Range categories which reduces the retained amount from \$7.77 million to \$6.22 million, an additional reduction of \$1.55 million. (York 3 Tr 1371-75.)⁷

⁷ It's important to note that this 40% figure is conservative. As ABATE witness York explained, the "additional 10 percentage point reduction relative to the 50% retention proposed by DTE does not attempt to separately quantify the effect of capacity factors falling to 11% and 14%." (York 3 Tr 1371-75.)

c. Other power generation O&M and the Blue Water Energy Center periodic outage normalization.

References in the Record: York 3 Tr 1375-80, Exhibit AB-8, Exhibit AB-27; Guillaumin 4 Tr 3451-53, 3467-70, 3473, Exhibit A-13; Coppola 4 Tr 5513-15.

DTE's projected other power generation O&M expense includes a \$2.75 million adjustment described as "BWEC Normalization of Periodic Spend" derived by taking a forecast of \$14.247 million for the 2026 Blue Water Energy Center major periodic outage, dividing by a four-year outage cadence to produce \$3.562 million, and subtracting \$810,189 of outage spend recorded in the 2025 historical test period. (Guillaumin 4 Tr 3451-53; Exhibit AB-8 at 50-51.) DTE confirmed that the next BWEC major periodic outage is not expected until 2030. (Exhibit AB-8 at 50.)

The normalization also drives nearly all of the above-inflation growth in other power generation maintenance expense. Excluding battery storage O&M associated with the Oracle energy storage agreement, maintenance expense within other power generation rises from \$18.56 million in 2025 to \$22.28 million in the projected test period, an increase of 20.0% compared to DTE's composite inflation factor of 6.5%. (York 3 Tr 1376; Exhibit AB-8 at 31-35.) At the same time, DTE capitalizes recurring peaker maintenance on the stated ground that doing so avoids incremental O&M, yet it reflected no corresponding O&M reduction for those capital projects. (York 3 Tr 1376-77; Exhibit AB-8 at 49, 54.) That raises the question of whether recurring maintenance scope is being recovered both through rate base and through O&M, which is precisely the question presented by the BWEC normalization. (York 3 Tr 1377.)

The three largest line items in DTE's \$14.247 million outage forecast are \$4,231,411 for "CTG 11-Turbine," described as "CSA cost, I&C PMs, equip operator, scaffold, insulation, electrician," an identical \$4,231,411 for "CTG 12-Turbine," and \$920,000 for "STG1-Turbine Valves," described simply as "turbine valves." (Exhibit AB-8 at 51.) Together these line items

total \$9,382,821, or 65.9% of the forecast. (York 3 Tr 1378-79.) DTE separately capitalized \$23.5 million for the BWECC CTG11 hot gas path overhaul, \$23.9 million for the CTG12 hot gas path overhaul, and \$6.2 million for the BWECC steam turbine valves project, all placed in service in April 2026, during the same outage window. (*Id.*; Exhibit AB-8 at 2-3.) DTE confirmed that the hot gas path overhauls “were completed as part of a long-term service agreement with the OEM.” (Exhibit AB-8 at 2.) Thus, DTE appears to be levelizing into O&M, and recovering from customers over a four-year cycle, outage costs for the same turbine and valve equipment on which it capitalized \$53.6 million of work during the same outage and placed that capital in rate base. (York 3 Tr 1379.)

ABATE therefore recommended that the Commission remove the \$2.35 million levelized portion of the normalization attributable to these three line items unless DTE demonstrated in rebuttal that none of that scope is also recovered through the capitalized projects and, if DTE made that demonstration, that the normalization be trued up to the actual cost of the 2026 outage. (*Id.*) DTE has done neither. Specifically, in rebuttal DTE asserted that the O&M and capital work are “separate, distinct, and justified,” and described the O&M work in general terms: instrument inspections, “inspection and repair of combustion and turbine components not replaced under capital,” compressor, casing, and bearing inspections, valve inspections and repairs, and “the O&M contribution for support services including insulation and scaffolding.” (Guillaumin 4 Tr 3468-69.) That narrative is not the demonstration ABATE identified, for three reasons. First, it is unquantified. DTE did not identify the cost of any activity it describes, did not tie any of them to the \$4.23 million turbine line items or the \$920,000 valve line item, and did not produce work orders, invoices, or other cost-level support. Second, the only exhibit DTE cited for the O&M scope, Exhibit AB-8 at 51, is the normalization workpaper itself, which contains none of the detail

DTE describes; it identifies the turbine line items only as “CSA cost, I&C PMs, equip operator, scaffold, insulation, electrician” and the valve line item only as “turbine valves.” (Exhibit AB-8 at 51.) Third, the first-listed element of each turbine line item is “CSA cost,” and DTE performed the capitalized hot gas path overhauls under a long-term service agreement (“LTSA”) with the OEM. (*Id.* at 2, 51.) DTE confirmed in discovery that it incurred \$28.3 million under the LTSA for the 2026 outage, charging \$5.6 million to O&M and capitalizing \$22.7 million. (Exhibit AB-27 at 27.) That LTSA amount charged to O&M represents roughly 91% of the actual O&M DTE reports for the two combustion turbines. (*Id.* at 27-28.) DTE has never explained the basis for that split, nor did it explain how shared support costs (scaffolding, insulation, equipment operators, and trades needed to access the same turbines and valves for both the capital replacements and the O&M inspections) were allocated between capital and O&M.

DTE’s discovery responses confirm that it cannot make the showing at issue. When ABATE asked for the actual cost of the 2026 outage by work order, with the amount charged to O&M and the amount capitalized for each, DTE objected that the request would require reviewing nearly 350 work orders. (Exhibit AB-27 at 27.) DTE further stated that it records O&M expense “at the system-level detail, but not component-level detail,” and that it “does not record its actual O&M expenses along the categories used” in its normalization workpaper. (*Id.*) In other words, DTE forecast the normalization by component but does not track actual O&M by component, and it declined to produce the work-order detail that would show whether turbine and valve scope charged to O&M overlaps the capitalized work. DTE’s acknowledgment that it is typical to incur both capital and O&M costs on the same equipment during a single outage (Guillaumin 4 Tr 3468) confirms that an allocation was required; it does not show that the allocation was performed correctly or that the forecast reflects it.

DTE's response to the true-up recommendation fares no better. DTE stated that the purpose of the normalization "is not to recover the specific cost of the 2026 outage," but rather "to levelize future periodic maintenance expense forecasts." (Guillaumin 4 Tr 3470.) But the only input DTE used to set the levelized amount is its forecast of the 2026 outage; DTE presented no estimate for the next major outage, which it expects in 2030. (Exhibit AB-8 at 50-51.) The 2026 outage has now occurred, and its actual cost is the best available evidence of what a BVEC major periodic outage costs. In discovery, DTE reported actual 2026 outage O&M of \$3,028,886 for the CTG 11 turbine, \$3,111,245 for the CTG 12 turbine, and \$1,764,958 for the STG1 turbine, a total of \$7,905,089, compared with \$9,382,821 forecast for the corresponding line items. (Exhibit AB-27 at 28; Exhibit AB-8 at 51.) DTE did not acknowledge those actuals in rebuttal. A pre-outage forecast is not a more reliable basis for a levelized expense than the actual cost of the very outage on which the forecast was built. DTE's assertion that future major outages will be "expanded" in scope is likewise unquantified and cannot substitute for that evidence. (Guillaumin 4 Tr 3473.)

DTE bears the burden of demonstrating that its projected expense is reasonable and prudent. Having failed to quantify the separation between O&M and capital scope for the turbine and valve work, and having conceded that it does not track actual O&M at the component level on which its normalization is built, DTE has not supported the \$9.38 million of turbine and valve line items included in its forecast. The Commission should therefore remove \$2.35 million from projected test period other power generation O&M, representing the \$9,382,821 attributable to the CTG11 turbine, CTG12 turbine, and STG1 turbine valve line items divided by DTE's four-year

outage cadence. (York 3 Tr 1379.) This leaves a normalization of approximately \$0.41 million after the \$810,189 historical credit DTE applies.⁸ (*Id.*)

In the alternative, if the Commission finds DTE's scope explanation sufficient, it should at a minimum true up the normalization to the actual 2026 outage costs DTE reported. Replacing the \$9,382,821 forecast for the turbine and valve line items with the \$7,905,089 actual reduces the levelized amount by approximately \$0.37 million (\$1,477,732 divided by DTE's four-year cadence). (Exhibit AB-27 at 28; Exhibit AB-8 at 51.)

2. Distribution O&M expense.

a. Preventative and corrective maintenance.

References in the Record: Fitzhenry 3 Tr 1418-22; Robinson 4 Tr 3981-84, 4032-34, 4041-44; Hartley 4 Tr 4520-21; Hill 4 Tr 4905-07.

DTE requested additional revenues of \$8.4 million during the 14-month bridge period and an additional \$250,000 in the projected test year for preventative maintenance, and an incremental O&M adjustment of \$9.1 million and capital adjustment of \$31.1 million in the projected test year for corrective maintenance. (Robinson 4 Tr 3981-84.) Given DTE's historic revenue sufficiency and the flaws in its proposal these increases are not reasonable.

While DTE asserted that these revenue increases are necessary to address backlogs, it's important to consider the context of DTE's \$87.5 million revenue sufficiency for the historical 12-month period ending December 31, 2025. (*Id.*; Fitzhenry 3 Tr 1418-22.) This sufficiency represents an extraordinary amount that ratepayers have already provided DTE intended to fund its costs for ordinary, ongoing distribution maintenance, routine inspections, and timely equipment repairs. DTE's backlogs were self-produced by its operational decisions to underspend or divert

⁸ ABATE's adjustment is narrower than the Attorney General's recommendation to remove the normalization entirely. (Coppola 4 Tr 5513-15.)

resources away from core maintenance this sufficiency should have addressed. (Fitzhenry 3 Tr 1418-22.) Rather than fulfilling its service obligations, DTE deliberately deferred essential maintenance to increase earnings beyond the ROE authorized by this Commission. It is unreasonable to increase DTE's revenues by an additional \$17.75 million in O&M expense and \$31.1 million in capital expenditures to address backlogs that accumulated while the Company was collecting and holding \$87.5 million which could have been used for these programs. Customers should not have to pay ever more in rates for work DTE could have, but chose not to, pursue using the previous excess revenues it collected from customers. DTE's claims that it cannot manage O&M under existing revenues and surpluses does not merit additional rate increases, it indicates administrative failures for which customers should not be forced to pay. (Robinson 4 Tr 4034.)

Beyond the significant equitable concerns regarding DTE's decision to pocket almost \$90 million before requesting additional revenue for work it elected not to pursue, DTE's maintenance planning, cost tracking, and operational efficiency include multiple flaws. First, when asked to provide the number of contractor full-time equivalents utilized to justify escalating labor costs, DTE admitted that it "does not track the number of contract laborers utilized by its contractors." (Exhibit AB-9 at 14.) Without any metric for the number of contractors or labor productivity there is no basis for determining whether additional O&M will be deployed efficiently or prudently. (Fitzhenry 3 Tr 1418-22.) DTE's claim that "the absence of comprehensive contractor headcount data does not impede the Company's ability to effectively manage contractor labor or ensure that contractor costs remain reasonable" is both self-serving and, as demonstrated above and below, inconsistent with DTE's requests for additional revenue. (Hill 4 Tr 4906.) Further, [REDACTED]

[REDACTED]

[REDACTED] (Exhibit AB-10.) DTE's claim that maintenance expense has been increased across all programs as a result of labor inflation is therefore inaccurate. (Fitzhenry 3 Tr 1418-22.)

The requested revenue increase is unreasonable considering the revenue sufficiency DTE accrued during the same time it could have been addressing the claimed backlog and its proposal contains flaws which demonstrate it is unnecessary. As such the Commission should deny DTE's requests for \$8.65 million in incremental preventative maintenance O&M expense, as well as its request for \$9.1 million in incremental Corrective Maintenance O&M expense and \$31.1 million of related capital expenditures.

b. Vegetation management.

References in the Record: Stults 2 Tr 276-82; Duell 2 Tr 786-93; Fitzhenry 3 Tr 1422-24; Hutchinson 4 Tr 3183-99, 3214-33; Coppola 4 Tr 5420-21; Stephens 4 Tr 5549-51.

DTE requested \$229.0 million in base O&M funding for 2027 (a \$49.0 million increase over the 2026 approved base level of \$180.0 million) to trim 6,554 miles on a 5-year cycle. (Hutchinson 4 Tr 3192.) As this proposed work and forecasted costs are not reasonable the Commission should reject this request.

In its February 19, 2026 Order in Case No. U-21860 the Commission noted that it "expects tree trimming expenses to decline once the 'surge' is completed and the company is on the recommended five-year cycle." As such the Commission stated it would "continue to closely scrutinize the company's progress and projected expenses." Given this context, and the revenue increase the Commission approved in February, it is alarming that DTE admitted it "has not spent any portion of the \$20 million regulatory asset through July 31st and does not anticipate that it will spend any of the regulatory asset by the end of 2026," and that it "does not anticipate that it will have trimmed incremental miles as it relates to the authorized regulatory asset." (Exhibit AB-9 at

5-10.) Thus, despite the Commission approving an additional \$20 million of revenue in Case No. U-21860 in response to DTE's claim that it "will not be able to trim the required miles in the test period aligned with a fixed five-year cycle with the requested O&M funding in the instant case of \$180 million," that additional \$20 million has not been touched or resulted in any additional miles trimmed. (Case No. U-21860, February 19, 2026 Order at 317.)

Despite being granted a \$20 million increase in Case No. U-21860 DTE effectively created a self-imposed deficit in 2026 while now proposing ratepayers fund a massive \$49.0 million revenue increase in 2027. Beyond the imprudence of this approach, DTE's \$229.0 million total revenue request contains numerous excessive overheads and unproven scope expansions, including: (i) \$16.5 million for General Foreman contractor oversight; (ii) \$7.68 million for third-party planning; (iii) \$3.2 million for arborist auditing; and (iv) unquantified amounts for other scope changes for which the Company admits it has only tested on a single circuit. (Exhibit AB-9 at 5-10; Hutchinson 4 Tr 2198-99; Fitzhenry 3 Tr 1422-24.) DTE's assertion that it will not "be able to proceed with any level of organization or efficiency" if it is held to the same level of revenue as past years does not indicate its projection is reasonable, it indicates DTE's ability to manage its costs merits additional scrutiny. (Hutchinson 4 Tr 3226.)

DTE has failed to utilize any of the additional revenues the Commission approved in U-21860 and its proposal here contains inflated and unreasonable amounts. Given these deficiencies the Commission should reject DTE's requested revenue increase of \$49.0 million and should hold the test-year vegetation management O&M expense to the \$180.0 million amount approved in Case No. U-21860.

3. Investment Recovery Mechanism.

References in the Record: Stults 2 Tr 265, 290-92; McGovern 2 Tr 417-21; Gerken 2 Tr 594-98; Evans 2 Tr 640-47; Becker 2 Tr 848-57, 861-62; Dauphinais 3 Tr 1303-11; Vangilder 4 Tr 3142-61; Robinson 4 Tr 3887-4089; Chiu 4 Tr 4320-77; Stephens 4 Tr 5598-601.

DTE submitted both primary and alternative proposals in this case regarding its IRM. Its primary proposal would: (i) add a Year 5 (2028), Year 6 (2029), and Year 7 (2030); (ii) increase annual authorized capital expenditures by \$255.7 million (90.5%) in 2028, \$180.4 million (33.5%) in 2029, and \$76.4 million (10.6%) in 2030, for a cumulative increase of \$512.5 million (181.4%). (Chiu 4 Tr 4322-25.) DTE's alternative proposal for 2027 and 2028 would increase existing authorized 2027 capital expenditures by \$163.4 million (57.8%) and proposed authorized 2028 capital expenditures by \$107.6 million (20.0%). (*Id.*) Given the proposed amounts and timeframe the Commission should restrict the use of DTE's IRM to avoid excessive revenues.

In the context of using projected test year costs to establish rates, an IRM can be a beneficial mechanism to the extent it specifies project and unit costs and requires refunds for unused revenues. (Dauphinais 3 Tr 1303-11.) The mechanism can also, however, become a tool for unreasonably and greatly expanding revenues and distribution investments at the expense of ratepayers well beyond the projected test year and regardless of need or cost effectiveness. As such the following should be ensured: (i) there is an urgent and undisputed need for each included investment and each has been robustly shown to be the most cost effective way to address the need, (ii) the years authorized for the Distribution IRM do not go beyond the projected test year any more than necessary, and (iii) cost categories are not defined overly wide such that the utility is able to avoid a greatly needed authorized investment and instead making an alternative investment in the same category with a lower degree of need. (*Id.*) DTE's proposal here does not satisfy these assurances.

DTE's proposal would result in pre-authorization and recovery for massive distribution investments nearly three years beyond the projected test year. As the Court of Appeals has recognized, the further out costs are projected the more speculative they become. *In re Consumers Energy Co to Increase Rates*, 338 Mich App 239, 247; 979 NW2d 702 (2021) (discussing the Legislature's "understanding that the PSC would reject a test year set so far removed from circumstances actually in view as to render it less than workable or that, should the PSC adopt such a flawed test year, it would be subject to appellate challenges for unreasonableness"). Thus, approving cost projections over such an extended future period greatly increases the likelihood of cost overrecovery through single issue ratemaking, as the IRM mechanism does not consider decreases in expenses or increases in revenues that would offset the claimed revenue requirement approved in a past proceeding. (Dauphinais 3 Tr 1303-11.) DTE's proposal embodies this concern, as it explained that the "IRM authorizes program-level amounts" and "[s]pecific projects are selected and reviewed in advance of the planned investment year through the established IRM planning process." (Chiu 4 Tr 4370-71.) In other words, there is no Commission review of actual project expenditures; authorizing revenues far into the future for program *categories* invites more flexibility in using these amounts for projects which may not be a necessary or cost-efficient use of customer revenues.

Furthermore, DTE's IRM proposal would aggressively grow annual investments from the authorized level for Year 4 (2027) of \$282.5 million per year to \$538.2 million per year starting in proposed Year 5 (2028), \$718.6 million per year starting in Year 6 (2029), and \$795.0 million per year starting in Year 7 (2030). (Dauphinais 3 Tr 1303-11.) This represents nearly a three-fold increase over the annual amount authorized for 2027 in Case No. U-21860. (*Id.*) Such

extraordinary increases raise serious questions as to whether these investments are in fact urgently and undisputably needed or the most cost-effective way to address DTE's purported needs.⁹

Given the amount and timeframe of DTE's proposed increases the Commission should therefore reject DTE's proposed Distribution IRM Year 6 (2029) and Year 7 (2030) in this proceeding. The degree to which these periods extend beyond the projected test year here prevent them from being properly reviewed to determine their prudence and reasonableness. The Commission should also limit DTE's 2027 authorized Distribution IRM capital expenditures to the level authorized by the Commission in Case No. U-21860, and limit DTE's primary proposed 2028 Distribution IRM capital expenditures to include no more than \$200 million for PTMM, and limit DTE's proposed 2027 and 2028 Distribution IRM capital expenditures for each remaining program category (Distribution Automation, Subtransmission Redesign and Rebuild, Breaker Replacement, URD Replacement, and System Cable) to no more than the amounts set out below. (Dauphinais 3 Tr 1303-11.). The Commission must also adjust DTE's Distribution IRM Surcharge to reflect the final level of Distribution IRM investments, if any, it authorizes for DTE:

⁹ As discussed above, DTE's proposed increase in annual PTMM Distribution IRM investments is not adequately justified and indicates the authorized level of expenditures should not be increased beyond the current authorized level of \$200 million. (See Dauphinais 3 Tr 1303-11.)

<p style="text-align: center;">TABLE JRD-2</p> <p style="text-align: center;">ABATE Recommended Maximum Allowed</p> <p style="text-align: center;">Authorized Annual Investments</p> <p style="text-align: center;">Under</p> <p style="text-align: center;"><u>DTE's Distribution IRM</u></p> <p style="text-align: center;">(\$ Millions)</p>				
<u>Description</u>	<u>2027</u>	<u>2028</u>	<u>2029</u>	<u>2030</u>
<u>Downward Adjustments:</u>				
Distribution Automation	\$0.0	\$116.7	\$0.0	\$0.0
PTMM	\$200.0	\$200.0	\$0.0	\$0.0
Subtransmission Redesign & Rebuild	\$52.5	\$48.3	\$0.0	\$0.0
Breaker Replacement	\$15.0	\$16.7	\$0.0	\$0.0
URD Replacement	\$15.0	\$16.7	\$0.0	\$0.0
<u>System Cable</u>	<u>\$0.0</u>	<u>\$25.8</u>	<u>\$0.0</u>	<u>\$0.0</u>
Total of ABATE Maximums	\$282.5	\$424.2	\$0.0	\$0.0
Reduction from DTE Primary Proposal	\$0.0	\$114.0	\$718.6	\$795.0
Reduction from DTE Alternate Proposal	\$163.4	\$221.6	\$718.6	\$795.0

It is important to note that even under this recommendation DTE's authorized investments for Year 5 (2028) would still be \$141.7 million (50.2%) higher than the total investment the Commission authorized in Case No. U-21860 for 2027. (See Dauphinais 3 Tr 1303-11.) In other words, this recommendation still provides for DTE's IRM investments to grow, while simply ensuring that growth occurs at a reasonable level.

E. Revenue Deficiency Calculation.

References in the Record: Dauphinais 3 Tr 1290-93;

As set out below, ABATE's adjustments (include its ROE recommendation) reduce DTE's requested revenue increase of \$474.3 million by \$249.7 million (53%). (Dauphinais 3 Tr 1290-93.)

TABLE JRD-1	
ABATE Projected Test Year Revenue Requirement Adjustments (\$ Millions)	
Description	Amount
<u>Downward Adjustments:</u>	
Projected Production and Inflation O&M Expenses (York)	\$21.4
Projected Production Capital Expenditures ¹ (York)	\$2.7
Projected Distribution O&M Expenses (Fitzhenry)	\$74.7
Projected Distribution Capital Expenditures ¹ (Fitzhenry)	\$5.8
<u>Return on Equity and Capital Structure (Walters)</u>	<u>\$145.1</u>
Total of ABATE Revenue Requirement Adjustments	\$249.7
¹ This is at ABATE's recommended ROE of 9.4% and 50.00% permanent common equity ratio. At DTE's proposed ROE of 10.25% and permanent common equity ratio of 51.50%, the projected capital expenditure revenue requirement adjustments would be \$2.7 million (York) and \$6.0 million (Fitzhenry).	

If, however, the Commission adopts an authorized ROE greater than 9.4% or a common equity ratio greater than 50% these revenue requirement reductions would be larger. (*Id.*)

F. Cost of Service, Rate Design, and Tariffs.

1. Cost of service.

a. Production cost allocation.

- i. AG-MNSC's proposed production cost allocation is inconsistent with statutory requirements and inadequately supported.**

References in the Record: McGovern 2 Tr 415-17; Andrews 3 Tr 1563-77; Havumaki 4 Tr 5627-28; Goyanes 4 Tr 2140-55; Tsuchida 4 Tr 2187-98.

Despite MCL 460.11(1) requiring that the Commission “shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation,” AG-MNSC proposed that the portion of production plant classified as energy-related be set equal to DTE’s system load factor, inclusive

of large load, with the remainder classified as demand-related and allocated on 4-CP demand. (Havumaki 4 Tr 5627-28.) As this proposal is inconsistent with the statute and inadequately supported the Commission should reject it.

While MCL 460.11(1) provides that the Commission “may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service,” AG-MNSC provided no support for that determination. Instead, AG-MNSC asserted that large load customers with very high load factors will flatten DTE’s system load profile over time, meaning it is generally appropriate to “re-conceptualize the role of generation as less oriented to serving peak and more oriented to serving energy needs,” and that the Commission “identified inequities resulting from the 75-0-25 methodology” in its November 6, 2025 Order in Case No. U-21859. (*Id.*) Neither claim demonstrates that the current 4-CP 75-0-25 production cost allocator does not ensure that rates are equal to the cost of service. (See Andrews 3 Tr 1563-77.)

First, AG-MNSC’s support for its proposal is limited to an assertion that large load customers “will alter the overall system load factor” and “the overall system load profile over the years will become flatter” such that adjusting “the classification of production plant to reflect the actual system load factor gives formal credence to the increasing energy-serving purpose of generation.” (Havumaki 4 Tr at 5627-28.) These conceptual assertions do not provide a sufficient basis for the Commission to determine that the statutory method of cost allocation does not ensure that rates are equal to the cost of service, particularly considering the Commission’s consistent rejection of alternative cost allocation methods over the past several years, including in Case No. U-20561, Case No. U-20697, and Case No. U-20963. Indeed, the 4-CP 75-0-25 method has been approved in DTE’s last nine general rate cases. (Andrews 3 Tr 1330-31; 1564-67 (internal citations omitted).) While the proponents of changing the allocation in those proceedings submitted

analyses explaining specific alternative cost allocations, here AG-MNSC presented no analysis at all. Specifically, AG-MNSC did not calculate the load factor it proposes, did not identify the weighting that would result, and did not quantify the effect on any customer class. (*Id.*) Instead, AG-MNSC's position amounts to a proposal to replace the statutory allocator with a weighting to be determined later, based on a load factor to be calculated later. (*Id.*) This does not amount to a demonstration that the current method does not ensure that rates are equal to the cost of service, or that AG-MNSC's alternative would more accurately do so.

Furthermore, the load data on which AG-MNSC bases its recommendation does not support AG-MNSC's proposal. As explained by ABATE witness Andrews, a "change in annual system load factor does not change what causes DTE to incur fixed production costs," which is its need for sufficient capacity to meet its peak demand and resource adequacy obligations. (Andrews 3 Tr 1571.) Once that capacity is built those costs are fixed regardless of energy consumption or system load factor.

In addition, while AG-MNSC provided no analysis of when DTE's capacity need occurs or what drives it, DTE did present that analysis at the Commission's direction. In its February 19, 2026 Order in Case No. U-21860, the Commission directed DTE to run and present the standard coincident peak tests in this case and to comment on the potential for changing the production allocator based on seasonal load shifts. (Andrews 3 Tr 1332, 1566.) Using its monthly system peaks for 2021 through 2025, DTE's five-year average results were 31% on Test 1, 55% on Test 2, and 72% on Test 3, each well outside the ranges of 19% or less, 66% or higher, and 81% or higher that would support a 12-CP allocation. (Andrews 3 Tr 1332-33, 1571.) Each test confirms that DTE remains a strongly summer-peaking utility. (*Id.*) In addition to these analyses, DTE also added load in increments of 500 MW up to 3,000 MW, both uniformly across the year and

concentrated in the winter months. Under these potential conditions all three tests remained outside the 12-CP ranges at every increment in both scenarios. (*Id.*) In other words, the flattening of the load profile AG-MNSC predicts is precisely the condition these sensitivities tested for, and the results show that DTE's fixed production costs remain driven by summer peak demand even with that load on the system. (*Id.*) MISO resource adequacy requirements also reinforce this reality. As explained by ABATE witness Andrews, the capacity DTE must own or contract for within MISO Zone 7 is set by its June through September peak demand, meaning the "number of hours the fleet runs after that capacity is in place, which is what load factor measures, does not change the cost of the capacity" or the manner in which it is appropriate to allocate production costs. (Andrews 3 Tr 1572.)

AG-MNSC's own cost allocation and rate design proposals also demonstrate that its proposal is unnecessary. Here, AG-MNSC recommended removing large load customers, and the resources built to serve them, from DTE's shared production cost pool. (Havumaki 4 Tr 5627-28; Andrews 3 Tr 1573.) Instead they would be placed in a separate rate class, every generation, transmission, and distribution asset that would not have been built but for large load would be directly assigned to that class, and responsibility for the capital-related revenue requirement of those assets would remain with the large load class after the customers depart. (*Id.*) AG-MNSC also recommended that the large load class' share of embedded production plant be determined separately, through modeling of the class' actual use of existing capacity. (*Id.*) Separating this customer load, and the resources used or constructed and costs incurred to serve it, into a separate rate class effectively eliminates the claimed flattening. Stated differently, "[o]nce the data center load and its dedicated resources are directly assigned, what remains in the embedded production pool is the same fleet, sized for the same existing customers, serving the same summer-peaking

load shape it was built for.” (See Andrews 3 Tr 1564-73.) Nothing about the load shape of residential, commercial, or existing industrial customers would be changed, nor would the cost causation of the embedded fleet among those classes. (*Id.*) After data centers and their associated costs are removed, reweighting the allocation of embedded production plant toward energy has no relevance to the cost of serving data centers, which is instead addressed by the separate class and the direct assignment. (*Id.*) The reweighting proposed by AG-MNSC instead only shifts the cost of the existing production fleet from residential customers to existing high load factor primary customers who caused none of the investment animating AG-MNSC’s proposal.

Furthermore, regarding AG-MNSC’s claim that the Commission “identified inequities resulting from the 75-0-25 methodology” in its November 6, 2025 Order in Case No. U-21859, in that Order the Commission rejected MNSC’s proposal to include a load factor requirement in the large load tariff, agreeing with Consumers that “the relevance of load factor as it relates to the necessary investments was not adequately explained, given that the system must be built to accommodate 100% of the load.” (Andrews 3 Tr 1574-77; Case No. U-21859, November 6, 2025 Order at 107, 114-17.) This reasoning applies here as well; production capacity investment is caused by the load the system must be built to accommodate, which is the peak, not the average load factor. Furthermore, the inequities the Commission noted were the socialization of costs for new resources built solely to serve a large load customer across other classes. The appropriate remedy was to be found in the six cost allocation studies the Commission ordered, including the direct assignment studies which address this concern, and a requirement that Consumers demonstrate that the costs caused by a large load customer are not being paid for by other customers. (*Id.*) The Commission’s decision had nothing to do with the MCL 460.11 production cost allocation; it addressed an incremental cost problem and identified the potential solution:

placing large load customers in their own classes and including the incremental costs of serving them, which is accomplished in Large Load Study 6, as addressed in greater detail below.

The Commission's socialization concern is not addressed by reallocating the cost of DTE's existing production fleet among DTE's existing customers. This is particularly true here, where the projected test year contains essentially no data center load. (Andrews 3 Tr 1574-76.) As ABATE witness Andrews explained, the system load factor "inclusive of large load" that AG-MNSC proposes to use is therefore, for this test year, DTE's current system load factor. (*Id.*) Using the 60% energy weighting AG-MNSC offered as its example, ABATE witness Andrews updated DTE's class cost of service study for the projected test year and found that the proposal would shift approximately \$78.5 million (5.2%) of cost responsibility out of the Residential class, placing \$66.2 million (6.7%) on the Primary class and the remaining \$12.3 million on the Secondary and Lighting classes. (Andrews 3 Tr 1575-76.) Thus, every dollar of the \$78.5 million that AG-MNSC's example would remove from the Residential class would be placed on DTE's existing customers without any impact from large load customers at all. (*Id.*)

AG-MNSC has therefore failed to demonstrate the statutory production cost allocation does not ensure rates equal to the cost of service. As such its recommendation should be rejected.

b. Large load class cost of service study.

i. The Commission should adopt Study 6.

References in the Record: Machi 3 Tr 1660-82; Andrews 3 Tr 1335-44, Exhibits AB-4, AB-5, AB-6, and AB-7; Goyanes 4 Tr 2142-46, Exhibit A-42; Havumaki 4 Tr 5636-43.

Consistent with the Commission's December 18, 2025 Order in Case No. U-21990 DTE filed six large load cost allocation and rate design studies in this proceeding. (Andrews 3 Tr 1335-44; Goyanes 4 Tr 2142-46; Machi 3 Tr 1660-61.) These studies demonstrate that each large load customer should be placed in its own rate class, separate from Rate D11 and the other primary

customer classes, with the incremental costs incurred to serve each customer directly assigned to that customer, as set out in Study 6.

Reviewing the revenues that existing Rate D11 customers, both full service and retail open access, would pay under the rates produced by each study demonstrates that existing D11 customers pay the least under Studies 5 and 6, which produce identical results for existing customers, and the most under Study 1, which places large load customers inside Rate D11. (Andrews 3 Tr 1335-44; Exhibit AB-5.) Specifically, existing D11 customers pay \$44.6 million per year more under Study 1 than under Studies 5 and 6 (\$42.5 million for full service customers and \$2.1 million for retail open access customers), or approximately 4.7% of their revenues under Study 1. (*Id.*) This results from the costs of serving the large load customers being allocated to the Rate D11 class without the resulting rate design recovering those costs from the large load customers under Study 1. (*Id.*)

Including large load customers in Rate D11 would therefore overwhelm the class. (*Id.*; Exhibit AB-6.) As of December 2025, Rate D11 served 2,065 full service customers with average monthly billed demand of 1,902 MW in the 2025 historical test year, and the largest existing customer had an average monthly billed demand of 208.6 MW, with the tenth largest at 25.6 MW. (Andrews 3 Tr 1338-39; Exhibit AB-6.) Indeed, each of DTE's two data center customers, at 1.4 GW and 1.0 GW of contracted capacity, would by itself be several times larger than the largest customer the class has ever contained, and together they would approach the billed demand of the entire existing class. (*Id.*) As ABATE witness Andrews explained, "[p]lacing loads of this magnitude and character inside a class of traditional commercial and industrial customers would distort the class load characteristics that drive cost allocation and rate design, and would expose the existing members of the class to intra-class subsidies, because rate design within a class does

not necessarily align with the basis on which costs are allocated to the class.” (Andrews 3 Tr 1335-44.) The Commission has made clear that a “core tenet of ratemaking is that customers are responsible for the costs they impose on the system and the costs required to serve them,” and “[r]esidential, commercial, and other industrial customers should not have to pay for investments driven solely by large load additions.” (Case No. U-21859 November 6, 2025 Order at 116.) Separate rate classes, with direct assignment of incremental distribution costs and the generation and transmission adjustment discussed below, implement this principle. (Andrews 3 Tr 1340-44.)

Establishing separate classes for these customers benefits every existing customer class. (*Id.*) This is evidenced in Exhibit AB-7, which provides a comparison of total proposed revenues for each class under Large Load Study 1, which places the data center load into D11, versus the total revenues for each class under Large Load Study 6, which places each data center customer into its own class, with the incremental distribution investment directly allocated. (*Id.*) Specifically, Study 6 both ensures existing Rate D11 customers are not allocated these costs, and that the incremental \$260 million distribution costs assigned to the large load customer class in Study 5 are assigned to the specific customer causing the cost in Study 6. (*Id.*; Exhibit AB-5.) Conversely, by combining the large load customers into a single class, Study 5 would socialize costs associated with one particular customer to the class, thus creating the same subsidy problem as including these customers in Rate D11. (*Id.*) Under Study 6, Customer 1 (Oracle) shows a distribution revenue deficiency of \$41.1 million, while Customer 2 (Google), which has no directly assigned facilities because it owns its own substation, shows a slight distribution sufficiency of \$1.6 million. (Andrews 3 Tr 1340, 1580; Exhibit A-42, Schedule AK1 at 2.) Study 5 combines those two very different cost positions into a single class result of \$39.5 million, so Customer 2 would bear a portion of the cost of a substation built exclusively for Customer 1. (*Id.*) There is no

reason to remove the large load customers from Rate D11 to prevent subsidization, only to then require various large load customers to subsidize each other under the Study 5 design. (*Id.*) DTE's assertion that the Study 6 approach is too "administratively complex" does not justify such inequitable results. (Machi 3 Tr 1681.) Instead, DTE's explanation that "costs added to a class get smoothed out over all customers that take service on that class, and the class as a whole covers the cost of service" demonstrates the inevitable cost socialization that will occur if customers with significantly different load sizes are grouped together in one customer class. (*Id.*)

AG-MNSC argued that a class-level approach is more flexible where smaller customers or groups of customers may join the system later and DTE may build facilities to serve multiple large load customers. (Havumaki 4 Tr 5624; Andrews 3 Tr 1578.) Placing each large load addition customer in its own class as it contracts for service instead is at least as flexible as a combined class, and it provides a more accurate accounting of cost causation. (Andrews 3 Tr 1577-82.) For instance, if DTE were to construct a facility that serves more than one large load addition customer, the cost of that facility can be assigned among the customers it serves in proportion to their use of it, which is how the direct assignment of shared industrial substation costs already works in DTE's cost of service study. (*Id.*) In other words, AG-MNSC's concern does not require combining customers with different facilities into a single class. Indeed, AG-MNSC itself acknowledged that its own class-level approach "does not preclude directly assigning certain costs to individual large load customers should that be deemed appropriate." (Havumaki 4 Tr 5624.) The record shows that it is appropriate now; one of the two customers has a \$260 million substation built exclusively for it and the other does not. (See Andrews 3 Tr 1581.)

DTE's existing large load customers should therefore be placed in their own rate classes separate from Rate D11 and DTE's other existing primary service rates, including Rate D8, Rider

3 and Rider 10, with the incremental distribution costs incurred to serve each customer directly assigned to that customer, and all remaining costs allocated under the Commission-approved methodology, as reflected in Study 6. There should, however, be an adjustment to the extent the embedded cost power supply revenues to be collected from the customer fall short of the revenue requirement for the incremental generation and transmission investments necessary to serve that customer as determined in DTE's Clean Energy Plan ("CEP"), Renewable Energy Plan ("REP"), Energy Waste Reduction ("EWR") and Integrated Resource Plan ("IRP") filings. (Andrews 3 Tr 1343.) This is necessary because directly allocating only incremental distribution costs is not sufficient to protect existing customers against inter-class cost subsidies. (Andrews 3 Tr 1340-44.)

While Study 6 directly assigns the incremental distribution costs incurred to serve each large load customer, serving these loads will also require incremental generation and transmission investments which will be further identified in DTE's future CEP, REP, EWR, and IRP filings. These incremental costs will enter DTE's base rates in future rate cases and be allocated among all customer classes. (*Id.*) As ABATE witness Andrews testified, an "embedded cost of service study by itself cannot show whether the power supply revenues collected from a large load customer are sufficient to cover the revenue requirement of the incremental generation and transmission investments required to serve these customers." (*Id.*) Thus, all incremental revenues received from each large load customer should be compared to all incremental costs incurred to serve that customer and the customer's rates should be adjusted to recover any shortfall. This is consistent with the affordability backstop DTE itself proposed in Case No. U-22058, under which Google agreed to reimburse DTE if the costs to serve Google exceed the revenues paid under its agreements. (See Case No. U-22058 October 1, 2026 Order at 112-16.) It is also consistent with the Commission's conditional approval of the Oracle special contracts in Case No. U-21990, which

required that the customer's obligations at least cover the costs to serve the customer, including generation, transmission, and distribution costs. (Andrews 3 Tr 1340, 1344; Case No. U-21990 December 18, 2025 Order at 40.)

DTE's claim that there is no basis for treating incremental distribution costs differently from incremental generation and transmission costs overlooks why the two are handled differently. The incremental distribution facilities at issue are typically dedicated to the specific customer they were built to serve, and no other customer benefits from them, so their cost can be identified and directly assigned in the cost of service study. (Machi 3 Tr 1682; Andrews 3 Tr 1340.) DTE's cost of service study already directly assigns industrial substation costs in this manner, and the new substation's distribution costs are the only incremental costs DTE's own Studies 5 and 6 directly assign. (Andrews 3 Tr 1581; Exhibit AB-5.) The incremental generation and transmission investments needed to serve these customers will instead be identified through DTE's future CEP, REP, EWR, and IRP filings, and will enter base rates in future rate cases, where embedded cost ratemaking will spread them across all classes. (Andrews 3 Tr 1343-44.) Because an embedded cost of service study cannot show whether a large load customer's power supply revenues cover those costs, comparing each customer's incremental revenues to its incremental costs is the way to make sure the customer that caused those costs pays them. (*Id.*) That comparison reflects the same principle as DTE's own Affordability Backstop for Google and the Commission's conditional approval of the Oracle contracts, both discussed above. (*Id.*)

The Commission has previously indicated that the establishment of a separate rate (or rates) for these customers was an issue to be determined in a rate case with information necessary to consider those customers' load characteristics. (See Case No. U-21859 November 6, 2025 Order at 104-105; Case No. U-22058 October 1, 2026 Order at 132.) This proceeding provides that

information and the cost allocation studies necessary to establish separate rates. Under Study 6, with the generation and transmission adjustment described above, Rate D11 and other existing primary service customers will not bear the costs of serving these new large loads, which will instead be directly responsible for the costs they impose on the system. (Andrews 3 Tr 1340-44.) As such the Commission should approve separate rate classes for these customers consistent with Study 6.

ii. As stated AG-MNSC's support for Study 5 is unreasonable.

References in the Record: Andrews 3 Tr 1577-82; Havumaki 4 Tr 5609-24.

AG-MNSC recommended the Commission establish a single rate class for all large load customers and assign incremental generation, transmission and distribution costs to that class rather than to individual large load customers. (Havumaki 4 Tr 5609-24.) As stated, this proposal would implicate more customers than the data center load animating the need for a separate rate. As such it should not be adopted.

AG-MNSC's recommendation proposed "using the usage thresholds from DTE's large load tariff proceeding (Case No. U-22061) to determine class membership" without reference to the requirement that the load be *new* load. (*Id.*) As stated this proposal would not just remove large load addition customers (Oracle, Google and U-22061 Rate D11 Large Load Provision customers) from their current rate class (Rate D11), it would also remove all customers with existing load that is greater than 100 MW at a single site or greater than 100 MW across multiple sites in DTE's service territory. (Andrews 3 Tr 1577-82.) This is not appropriate given the significant differences between the large load customers at issue and existing customers, particularly the fact that the latter do not present the same incremental cost issues as large load addition customers. (*Id.*) Indeed,

AG-MNSC points to no historic issues or changed circumstances with regard to serving them in their current rate class. (Andrews 3 Tr 1579.)

Existing load that is greater than 100 MW at a single site or greater than 100 MW across multiple sites beyond Oracle, Google, and U-22061 Rate D11 Large Load Provision customers does not present the problems to be addressed by a separate rate class. The Commission should therefore reject AG-MNSC's proposal to use the usage thresholds from DTE's large load tariff proceeding (Case No. U-22061) to determine class membership.

2. Tariff issues.

a. Large load transition mechanism.

References in the Record: Stosik 2 Tr 611-29; Dauphinais 3 Tr 1299-303, Exhibit AB-1; Bruzzano 4 Tr 1996-97; Foley 4 Tr 2034-65; Jester 4 Tr 5332-35; Coppola 4 Tr 5535-38.

This issue concerns DTE's projected sales to its super scalar data center customer Oracle America Cloud Services LLC ("OACS") and the impact that additional sales will have on the projected revenue requirement in this case. Specifically, DTE proposed a Large Load Transition Mechanism ("LLTM") designed to address a circumstance in which DTE's actual sales to OACS during the projected test year exceed the sales DTE has assumed ("OACS Excess Sales"), resulting in a sales margin that is not reflected in DTE's calculation of its claimed revenue deficiency here ("OACS Excess Margin"). (See Dauphinais 3 Tr 1299-303.) The LLTM contains a number of flaws that must be addressed.

First, DTE proposes to terminate the LLTM after February 29, 2028 and use the margin from OACS sales to fund what it determines to be appropriate for "supporting the Company's objective of providing safe and reliable electric service." (Exhibit AB-1 at 1-3.) This effectively provides DTE with an opportunity to engage in unregulated spending and further earn a return in excess of that authorized by the Commission. Second, although DTE asserted that "for the period

beginning March 1, 2028 and continuing until new rates are established following its next rate case, if its weather-normal earned ROE exceeds its authorized ROE on a ratemaking basis [DTE] will record these excess earnings (appropriately adjusted for taxes) in a regulatory liability to be returned to customers as a bill credit,” there is no indication that regulatory liability will be returned to all customer classes based on cost of service principles. (*Id.*; Dauphinais 3 Tr 1299-303.) These flaws do not work in favor of customers’ interests.

DTE’s objection to a contested case filing to ensure a cost-based return of any regulatory liability to customers is also deficient. DTE asserted that “the Commission has the authority to order a contested case if it deems such an approach appropriate at the time the Company makes its future LLTM regulatory liability filing.” (Foley 4 Tr 2061.) Given DTE’s acknowledgment of the Commission’s authority, as well as the unknown and potentially significant sums at issue, such a contested case should be required here. DTE also stated that “it is possible that the LLTM regulatory liability will be zero or relatively small” and “a contested case would likely delay the use of the LLTM regulatory liability, which the Company plans to propose be returned to customers as a bill credit, and the realization of any associated benefits by the Company’s customers.” (*Id.*) Again, it is not clear how exactly any bill credit would be allocated amongst customers and it is prudent to establish the process for reviewing that issue now.

Given these flaws, approval of the LLTM should be contingent upon DTE taking the following action:¹⁰

- Modifying the termination date of the LLTM to the day prior to new base rates going into effect following DTE’s next general rate case proceeding;

¹⁰ The LLTM also allows DTE to rid itself of significant sales risk it would otherwise have during the projected test year. (Dauphinais 3 Tr 1299-303.) This arrangement secures DTE shareholders both a large return and Financial Compensation, both of which should be considered in setting DTE’s authorized ROE in this proceeding.

- Making the required June 1, 2028 filing regarding the disposition of the of the LLTM regulatory liability, and any similar filing thereafter, a contested case filing to ensure the regulatory liability is returned to all customer classes in a manner consistent with cost-of-service principles; and
- Filing quarterly compliance reports on the status, calculation and current balance of the LLTM regulatory liability

Without these modifications the LLTM serves shareholders, rather than ratepayers. As such these revisions are necessary to ensure DTE's proposal is reasonable and prudent.

b. Power factor provisions.

References in the Record: Dauphinais 3 Tr 1312-20, Exhibit AB-28; Turner 4 Tr 3113-19, 3122-31.

In contrast to its current separate power factor provisions for full service and choice customers (i.e., energy-based and demand-based), DTE here proposed a single methodology applicable to all primary customers with three major components: (i) adoption of a \$/excess kVAR charge for all primary customers, consistent with the structure of the existing retail access penalty; (ii) a standardized power factor penalty threshold of 0.850, with excess kVAR measured relative to the kVAR corresponding to a 0.850 power factor; and (iii) measurement of reactive demand at the customer's maximum monthly kW demand interval, rather than at on-peak demand (in the case of retail access) or on an energy basis (in the case of full service). (Turner 4 Tr 3114-19; Dauphinais 3 Tr 1312-20.) The proposed \$/excess kVAR charges include a \$4.68/excess kVAR for customers with a power factor below 0.85 but not persistently below 0.700, and \$18.31/excess kVAR for customers whose power factor is below 0.700 for more than two consecutive months. (*Id.*) This proposal is flawed in certain respects and should not be approved.

First, DTE has not justified why the power factor level triggering the kVAR charges should be increased from 0.800 to 0.850. (Dauphinais 3 Tr 1312-20.) Second, DTE has also not justified increasing the kVAR rate from \$3.50/ kVAR to \$4.68/kVAR or demonstrated that either is actually

based on the cost for capacitor banks which serve as the principal tool for power factor correction. (*Id.*) Rather than reflect its costs DTE instead designed its proposal to be revenue neutral. Third, there is no evidence DTE consulted customers that would be affected by the change to explain the potential cost impact. Finally, the proposal does not include any per kVAR *credit* to customers who provide superior power factor that reduces the amount of power factor correction required on DTE's system. (*Id.*)

Regarding the power factor threshold, DTE provided no basis for revising the 0.800 historically used for retail open access customers. (Dauphinais 3 Tr 1312-20; Turner 4 Tr 3114-19.) As the current kVAR charge for retail open customers has long been sufficient there is no basis for increasing it from 0.800 to 0.850 at this time. Indeed, while DTE asserted that the "0.850 threshold is not a new concept," it provided no explanation of why the threshold for choice customers needs to be increased to this amount. (Turner 4 Tr 3124-25; Exhibit AB-28 at 3-5.) Regardless of DTE's claim that its "proposed 0.850 threshold is not unusually stringent when compared to other Michigan utility power factor thresholds," it has provided no basis for increasing the threshold for choice customers and explicitly acknowledged that "each utility's tariff design must be evaluated on its own terms." (*Id.*) As such this modification is inadequately supported.

DTE similarly failed to demonstrate why it is reasonable or necessary to increase its excess kVAR charge from \$3.50 per kVAR to \$4.68 per kVAR. (Dauphinais 3 Tr 1312-20; Turner 4 Tr 3125-27.) Instead, the Company simply asserted its purpose was to maintain revenue neutrality for itself and, when explicitly asked why it "believes it is reasonable to charge a customer a higher dollar amount of power factor adjustment charges if the customer is taking bundled electric service rather than retail open access service," DTE simply stated that its "proposal in this proceeding is intended to eliminate the current difference in treatment between bundled and retail open access

customers.” (*Id.*; Exhibit AB-28 at 13-14.) Further, while DTE asserted that without its proposed changes costs would be increased for other customers, it acknowledged that it did “not assume any power factor penalty revenue in the projected test year” and “does not forecast customer power factors,” meaning it has no basis for making that claim and has not demonstrated its proposal is reasonable. (*Id.*; Exhibit AB-28 at 15, 50.) In other words, DTE’s proposal to increase the power factor threshold and charge for choice customers is based on nothing other than administrative parity, not cost causation. The unreasonableness of its proposal is demonstrated by the analogous charges for Michigan’s other large utilities. Consumers Energy Company, for instance, has a current excess kVAR charge of only \$1.14 per kVAR, and Indiana Michigan Power Company’s current excess kVAR charge is \$1.50 per kVAR. (Dauphinais 3 Tr 1312-20 (internal citations omitted).) Considering this context and DTE’s lack of adequate support the Commission should reject DTE’s proposal and require DTE to develop and file a cost-based rate for its excess kVAR charge in its next rate case.

DTE’s lack of customer outreach also justifies rejecting its proposal here. DTE’s proposal will not be neutral to the customers subjected to it. Some will likely pay significantly more and others less for poor power factor performance. (*Id.*) Given these implications, customers should be provided sufficient advance notice, information, and assistance from DTE such that they can determine the expected dollar impact and pursue alternatives, as necessary. The six months DTE indicated it would take to implement the changes do not appear to include any actions to help prepare customers. (Turner 4 Tr 3114-19; Dauphinais 3 Tr 1312-20.) As such, the Commission should require that DTE: (i) within 90 days of the final Commission order in this proceeding, provide to each affected DTE customer notice, information, and assistance with respect to the specific cost impact the power factor changes are expect to have on that customer; and (ii) not be

permitted to implement any Commission-approved power factor provision changes any earlier than six months after the 90-day customer notification deadline.

DTE's failure to provide a credit for superior power factor performance is also unreasonable. As ABATE witness Dauphinais explained, "superior power factor performance by some customers can significantly decrease the amount of power factor correction that a utility has to perform on its system with capacitor investments due to poor power factor performance by other customers located in the same general area of the utility's system." (Dauphinais 3 Tr 1312-20.) Consumers Energy Company recognizes this by providing a kVAR credit for power factor performance in excess of a given power factor threshold. (*Id.* (internal citation omitted).) Given its impact on DTE's system the Commission should require DTE to, in its next general rate case proceeding, file a per kVAR credit for superior power factor performance equal in magnitude to the per kVAR charge for power factor performance. This recognizes the system cost *and* benefit provided by customer power factors.

While DTE's attention to its power factor provisions is appreciated, its proposal in this case should be rejected. Instead, the Commission should require DTE to modify its tariff to apply its current 0.800 power factor threshold and \$3.50 per kVAR charge for retail open access customers to its full (bundled) service customers, develop and file a cost based rate for its excess kVAR charge, provide customers notice, information, and assistance regarding any power factor change as set out above,¹¹ and file a proposal to provide a per kVAR credit for superior power factor

¹¹ While ABATE does not object to applying an excess kVAR charge of \$18.31 per kVAR to both full service and retail open access customers with power factors below 0.700 for more than two consecutive months, this charge should not be applied before any power factor provision the Commission ultimately approves in this proceeding is implemented on the timeline discussed above, and any such charge should be reassessed in DTE's next general rate case proceeding. (Dauphinais 3 Tr 1312-20.)

performance equal to DTE's per kVAR charge for power factor performance. These measures will both remove the current differential treatment between full (bundled) service and retail open access customers, provide for excess cost based kVAR charges, and result in power factor provisions that appropriately reward superior customer power factor performance.

IV. RELIEF REQUESTED

WHEREFORE, ABATE requests the Commission issue an Order adopting ABATE's positions as outlined in its Direct and Rebuttal Testimony, as well as its Initial Brief.

Respectfully submitted,

CLARK HILL PLC

Stephen A.

By: **Campbell**

Digitally signed by: Stephen A. Campbell
DN: CN = Stephen A. Campbell email =
SCampbell@clarkhill.com C = US O =
Clark Hill PLC
Date: 2026.10.26 14:38:55 -04'00'

Michael J. Pattwell (P72419)
Stephen A. Campbell (P76684)
Benjamin J. Holwerda (P82110)
Attorneys for the Association of
Businesses Advocating Tariff Equity
Clark Hill PLC
500 Woodward, Suite 3500
Detroit, Michigan 48226
313-309-4274
mpattwell@clarkhill.com
bholwerda@clarkhill.com
scampbell@clarkhill.com

Date: October 26, 2026

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the Application of)	
DTE ELECTRIC COMPANY)	Case No. U-22046
for authority to increase its rates, amend)	
its rate schedules and rules governing the)	ALJ Theresa A.G. Staley
distribution and supply of electric energy, and)	
<u>for miscellaneous accounting authority.</u>)	

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF WAYNE)

Stephen A. Campbell, being first duly sworn, deposes and says that on October 26, 2026, he did cause to be served the *Association of Businesses Advocating Tariff Equity's PUBLIC Initial Brief* as well as this *Proof of Service*, in the above docket, via electronic mail, to the persons identified on the attached service list.

**Stephen A.
Campbell**

Stephen A. Campbell

Digitally signed by: Stephen A. Campbell
DN: CN = Stephen A. Campbell email =
SCampbell@clarkhill.com C = US O = Clark
Hill PLC
Date: 2026.10.26 14:38:42 -04'00'

SERVICE LIST
MPSC Case U-22046

Party	Name	Email
Administrative Law Judge	Theresa A.G. Staley	staley1@michigan.gov
ABATE	Michael J. Pattwell	mpattwell@clarkhill.com
ABATE	Stephen A. Campbell	scampbell@clarkhill.com
ABATE	Lauren Degnan	ldegnan@clarkhill.com
ABATE Consultants	James Dauphinais	jdauphinais@consultbai.com
ABATE Consultants	Jessica York	jyork@consultbai.com
Citizens Utility Board of Michigan	Carrie La Seur	claseur@laseurlaw.com
City of Ann Arbor/Michigan Environmental Council	Valerie R. Jackson	vjackson@a2gov.org
Dept. of Attorney General	Joel B. King	KingJ38@michigan.gov
Dept. of Attorney General	Lucas Wollenzien	wollenzienL@michigan.gov
DTE Electric Company	Andrea E. Hayden	andrea.hayden@dteenergy.com
DTE Electric Company	Jon P. Christinidis	jon.christinidis@dteenergy.com
DTE Electric Company	Morgan Esters	morgan.esters@dteenergy.com
DTE Electric Company	Breanna Reitzel	breanne.reitzel@dteenergy.com
DTE Electric Company	Carlton Watson	carlton.watson@dteenergy.com
DTE Electric Company	MPSC Filings Account	mpscfilings_account@dteenergy.com
ELPC/Ecology Center/UCS/Vote Solar	Daniel H.B. Abrams	dabrams@elpc.org
ELPC/Ecology Center/UCS/Vote Solar	Katie Duckworth	kduckworth@elpc.org
ELPC/Ecology Center/UCS/Vote Solar	MPSCDocket	MPSCDocket@elpc.org
ELPC/Ecology Center/UCS/Vote Solar	Alondra Estrada	astrada@elpc.org
ELPC/Ecology Center/UCS/Vote Solar	Katie Toolan	ktoolan@elpc.org
Energy Michigan/MEIBC/FAM	Timothy Lundgren	tjlundgren@varnumlaw.com
Energy Michigan/MEIBC/FAM	Laura Chappelle	lachappelle@varnumlaw.com
Energy Michigan/MEIBC/FAM	Justin Ooms	jkooms@varnumlaw.com
Energy Michigan/MEIBC/FAM	Haylee Skank	hnskank@varnumlaw.com
Energy Strategies, LLC	Justin Bieber	jbieber@energystat.com
Gerdau MacSteel, Inc.	Jennifer Heston	jheston@potomacclaw.com
Michigan Cable Telecommunications Association	Sean P. Gallagher	sgallagher@fraserlawfirm.com
Michigan Cable Telecommunications Association	Joann M. Schofield, Legal Assistant	jaustin@fraserlawfirm.com
Michigan Municipal Association for Utility Issues	Michael Watza	mike@bloomsbuggett.com
Michigan Municipal Association for Utility Issues	Nathan Inks	nathan@bloomsbuggett.com
MPSC Staff	Daniel Sonneveldt	sonneveldtd@michigan.gov
MPSC Staff	Nicholas Q. Taylor	taylor10@michigan.gov
MPSC Staff	Amit Singh	singha9@michigan.gov
MPSC Staff	Anna B. Stirling	stirlinga1@michigan.gov
MPSC Staff	Lori Mayabb	mayabbl@michigan.gov
NRDC/CUB/MEC	Tracy Jane Andrews	tjandrews@tropospherelegal.com
NRDC/CUB/MEC	Christopher M. Bzdok	chris@tropospherelegal.com
NRDC/CUB/MEC	Holly L. Hillyer	holly@tropospherelegal.com
NRDC/CUB/MEC	Sean C. Clark	sean@tropospherelegal.com
NRDC/CUB/MEC	Natasha Fowles, Legal Assistant	natasha@tropospherelegal.com
NRDC/CUB/MEC	Sue Fruchey, Legal Assistant	sue@tropospherelegal.com
Oakland County	Sean P. Gallagher	sgallagher@fraserlawfirm.com
Oakland County	Geofrey C. Bilabaye	gbilabaye@fraserlawfirm.com
Oakland County	Jared A. Roberts	jroberts@fraserlawfirm.com
Soulardarity; We Want Green, Too	Amanda Urban	aurbanlaw@gmail.com
Soulardarity; We Want Green, Too	Alexandria C. Miskho	amiskho@uchicago.edu
The Kroger Company	Kurt J. Boehm	KBoehm@BKLawfirm.com
The Kroger Company	J Kyler Cohn	JKylerCohn@BKLawfirm.com
Walmart, Inc.	Melissa M. Horne	mhorne@hcc-law.com