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October 3, 2024

VIA ELECTRONIC CASE FILING

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

Re: Case No. U-21534 – 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 Initial Brief*** and ***Proof of Service*** in the above-referenced matter.

Sincerely,

CLARK HILL PLC

Stephen A. Campbell

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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 increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	)))))))	Case No. U-21534 ALJ Sally L. Wallace

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").

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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 the Company's use of a projected test year which inflates DTE's revenue requirement using conjectural expenses which are not reflective of DTE's actual costs. Further, numerous capital expenditure proposals are not adequately supported such that cost recovery is unreasonable at this time. In addition, the Company's requested return on equity ("ROE") and equity ratio are excessive, inadequately supported, and unnecessary, and its projected operations and maintenance ("O&M") costs are inflated and unreasonable. The Company's proposal to significantly expand its new investment recovery mechanism ("IRM") and multiple intervenor proposals regarding rate design are also imprudent at this time and should be rejected.

Accordingly, to ensure just and reasonable rates the Commission should adopt the recommendations set out below. These proposals will ensure DTE's rates are reasonable and prudent and that the Company's costs are allocated to customers consistent with the manner in which they are caused.

II. EXECUTIVE SUMMARY

The Company and multiple intervenors submitted various proposals in this proceeding which would not reflect just and reasonable rates. Regarding these proposals the Commission should take the following action:

- The Company's request to establish rate revenue based on projected test year expenses should be rejected. The Company has consistently overearned its authorized return and the use of projected test year expenses as the basis for establishing DTE's revenues continues to produce demonstrably unjust and unreasonable rates.

- If the Commission uses DTE's projected test year as the basis for establishing its revenue requirement it should disallow cost recovery of at least $19.8 million (using a 9.6% ROE, or $21.2 million using the Company's proposed ROE) in projected capital expenditures (in addition to associated depreciation and tax expense) due to a lack of competent, material, and substantial evidence on the record that these projected costs are accurate, likely to be incurred, or relate to projects which will be in service during the test year period.

- Given market trends, the Company's risk relative to comparable companies, and the results of various analytical methods the Commission should approve a ROE no higher than 9.6%.

- The Commission should disallow cost recovery of at least $93.9 million of the Company's projected O&M expenses as they relate to proposed incentive compensation and inflation rates which have not been adequately supported as reasonable or prudent by competent, material, and substantial evidence.

- The Commission should note the unreasonableness of MNSC's proposal to consider establishing distribution rates to reflect that the relative utilization of the distribution system is seasonal.

- Staff's proposal that purchased capacity costs be allocated using the 4CP 75-0-25 allocator does not reflect the fact that DTE's purchased capacity costs are largely related to renewable energy assets with costs that are largely fixed. As such the Commission should reject this proposal.

- The Company's proposal to expand its IRM is premature, unreasonable, and unnecessary and should be rejected.

- MEIU's proposal that DTE account for social benefits, including greenhouse gas and criteria pollutant emissions reductions, in its Benefit Cost Analysis ("BCA") for its Transportation Electrification Plan ("TEP") would separate the BCA from a proper consideration of quantifiable metrics and should be rejected.

III. ARGUMENT

A. Test Year – Considering DTE's history of exorbitantly overearning its authorized return the Commission should reject the use of a projected test year and base DTE's revenue requirement on the Company's historic test year.[1]

1. The Commission should reject the Company's use of projected costs as the basis for its revenue requirement.

The Company based its requested revenue increase on projected expenses. (See DTE Application at 2-3.) Because the use of projected test years has resulted in excessive over-recovery for DTE, including a reported historic revenue sufficiency of $80.5 million in this case, the Commission should instead approve a revenue requirement based on the Company's historic test year, which would eliminate the need for the Company's requested $456.4 million rate increase in its entirety.

As set out in MCL 460.6a(1) a utility "may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." Despite this permissive statutory language, however, a Commission Order approving such a proposal must be reasonable, meaning it is supported by competent, material, and substantial evidence. MCL 462.26(8); *Attorney General v Mich Pub Serv Comm*, 249 Mich App 424, 429 (2002). For instance, the Legislature's treatment of projected test years "reflects its 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." *In re Application of Consumers Energy Co*, 338 Mich App 239,

[1] This issue is addressed at Foley 2 Tr 91-92, 181-85 (recommending the Commission approve the use of a projected test year); Dauphinais 6 Tr 3370-79 (objecting to the use of a projected test year); Alvarez 6 Tr 3944 (explaining that forward test years shift the burden of proving prudence "from utilities (in traditional ratemaking, after the capital is spent) to intervenors, who must now prove imprudence when capital spending projects and programs are initially proposed").

247 (2021); see also *In re DTE Electric Co*, unpublished per curiam opinion of the Court of Appeals, issued February 25, 2021 (Docket Nos. 349924, 350008), p 11[2] (stating that "a utility that selects a test year set too far in the past or future would obviously risk rejection by the PSC, and doing so would likely make adjustments prohibitively difficult" and "[a]ny adoption by the PSC of such an inappropriate test year would also be subject to appellate challenges for unreasonableness").

As the Commission has also explained, where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections. *In re Detroit Edison*, order of the Public Service Commission, entered January 10, 2011 (Case No. U-15768), p 9. Utilities must include all evidence (or sources of evidence) in support of their test year projections in their initial rate case filings. *Id*. If the utility does not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data), "the Commission may choose an alternative method for determining the projection." *Id*. That alternative method should be the use of the historical test year amount for that item adjusted for only known and measurable changes to the amount for that item.

Indeed, as the Commission has stated previously, 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

[2] Also available at Case No. U-20162 Filing No. U-20162-0643 (February 25, 2021).

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*. In other words, the Commission is not required to base utility rates on projected costs and may instead utilize historic data when it is a more fair and reasonable indication of the utility's costs. The Commission should do so here.

The Company's use of projected test year expenses as the basis of its requested revenue has resulted in significant revenue increases beyond those necessary to meet the Company's authorized rate of return. Specifically in this case, as it has in the overwhelming majority of its recent rate cases, the Company again reported a substantial historic test year revenue sufficiency ($80.5 million here). (See Dauphinais 6 Tr 3370-79.) Given DTE's consistent inability to accurately project costs and revenues in a projected test year the Commission should reject the use of the projected test year here as it violates its responsibility to approve rates that are just and reasonable. See *Ass'n of Businesses Advocating Tariff Equity v Pub Serv Comm*, 208 Mich App 248, 259 (1994) ("Once the PSC's ratemaking authority is invoked [] the PSC may look at all relevant factors in exercising its broad discretion to determine a just and reasonable rate"); *Attorney General v Pub Serv Comm*, 189 Mich App 138, 146 (1991) (explaining "it is well settled that the universal test of the lawfulness of utility rates is that the rates be 'just and reasonable'"). The Commission should instead utilize the Company's historic test year as a more reasonable reflection of DTE's revenue requirement and costs.

Given DTE's own numbers it would not have been able to seek the exorbitant rate increases it has requested in its last six general rate cases, including this proceeding, if it been required to base its revenues on its historic costs. (Dauphinais 6 Tr 3370-79.) Stated differently, projected test

years allow DTE to begin recovering costs before they have been verified as real and prudently incurred which has significant detrimental impacts on ratepayers. The most important of these impacts is that customers experience excessive rate increases earlier than if the Company had used historical test years. (*Id*.) Further, projected test years eliminate the Company's incentive to contain costs that would otherwise exist due to regulatory lag, meaning they effectively cushion the Company's spending and reduce the Company's risk at ratepayer expense. (*Id*.) In addition, they permit the Company to include proposed expenditures in its projections which it has not committed to incurring and can avoid to improve its shareholders' rate of return. (*Id*.)

As demonstrated by its historic revenue sufficiencies, projected test years have allowed DTE to recover costs for ultimately unnecessary capital expenditures which it was not possible for Staff or other intervenors to identify during the Company's applicable rate case. (*Id*.) This last reality is effectively unavoidable when the Company uses a projected test year as part of its rate case filing; i.e., Staff and intervenors are tasked with an exacting review of the Company's voluminous application, testimony, and exhibits to ensure projected capital expenditures are reasonable. (*Id*.) This asks significantly more from stakeholders and customers than would be required if requested revenue increases were based on historical test years, particularly as rate case schedules are truncated and utility proceedings continue to overlap. In other words, given practical procedural realities, the use of projected test years will necessarily result in interested parties missing or failing to adequately challenge unreasonable and inappropriate cost projections which will ultimately be collected from customers. (*Id*.) These projected expenditures are not known and measurable; they are instead highly speculative and potentially avoidable.[3]

[3] The speculative nature of these potential costs is inherent in their projected nature. Indeed, as the Company acknowledged, "[s]ome of these costs will not occur for more than 20 months after the Company filed this case and are subject to factors outside of the Company's control." (Foley 2 Tr

This case further highlights the inequity of basing DTE's requested rate increase on cost projections given the Company's historic revenue surpluses. The Company has consistently reported large revenue sufficiencies for its historical test years, including between $80.5 million to $111.7 million from 2020 to 2022. (See *Id*.) Thus, in these historic test years DTE's rates were ultimately more generous than necessary to provide the Company a reasonable opportunity to earn its authorized return. Furthermore, these values reflect DTE's reported historic test year values which, if more closely examined, might very well reveal costs that are not recoverable in rates. (*Id*.) In other words, DTE's actual revenues in excess of its authorized rate of return in its historic test years may very well have been well in excess of the amount DTE has reported.[4] Ultimately, if DTE's rates for projected costs were being properly set they would not consistently result in revenue sufficiencies of this magnitude. (*Id*.) Instead, however, DTE is consistently being granted rate revenue based on projected costs that are clearly much higher than the Company is actually incurring, such that DTE is consistently earning a windfall of tens of millions of dollars per year. This significant overearning will not be curbed until the Commission takes action and either: (i) rejects DTE's projected test year; (ii) becomes much more aggressive in terms of rejecting DTE's unsupported projections; or (iii) institutes other measures that prevent or greatly limit DTE overearnings resulting from inflated projections.

183.) Thus, the Company's own testimony demonstrates the point made further below and throughout the record; that many of the capital expenditures and expenses DTE has attempted to recover in past general rate cases and is attempting to recover in this current proceeding are highly speculative and uncertain.

[4] "[T]he essential principle of the rule against retroactive ratemaking is that when the estimates prove inaccurate and costs are higher or lower than predicted, the previously set rates cannot be changed to correct for the error; ***the only step that the MPSC can take is to prospectively revise rates in an effort to set more appropriate ones***." *Detroit Edison Co v Mich Pub Serv Comm*, 416 Mich 510, 523 (1982) (emphasis added).

Given the detrimental results and inherent flaws in using projected test years, and considering the Company's historic test year sufficiency, the Commission should reject the Company's proposal to set its revenue requirement based on projected test year expenses in this case. As the Company has again reported a historic revenue sufficiency of $80.5 million the Commission should effectively reject the Company's request to again raise customer rates despite again earning tens of millions of dollars more than it required to provide electrical service. Thus, considering DTE's inability to accurately project cost and revenues in the projected test year the Commission should reject the Company's proposal to base its revenue requirement on projected test year costs here as it violates the Commission's responsibility to approve rates that are just and reasonable. The Company's historic test year is instead a more reasonable reflection of DTE's revenue requirement and costs and does not support a rate increase of any amount for the Company in its proceeding given the Company is reporting a rate sufficiency $80.5 million for its historic test year.

2. If the Commission considers projected costs as the basis for the Company's revenue requirement it must be exacting in ensuring those projections are accurate and the costs will be actually incurred as approved.

If, despite this recommendation, the Commission elects to approve the use of a projected test year it should to the following: (i) be much more diligent in holding the Company to its burden regarding its support for its projections and the reasonableness and prudence of its cost recovery; (ii) ensure DTE is irrevocably committed to incur the projected expenses or cannot otherwise avoid them; and (iii) ensure that DTE's projected investments and expenses are precisely quantified with respect to both amount and the specific quarter in which DTE will incur these investments and expenses. It is clear from DTE's historical test year revenues exceeding its authorized return that either questionable projections are not being caught in reviewing DTE's proposals, the

Commission has provided too great a benefit of doubt to DTE with respect to the projections questioned by intervenors and/or Staff, DTE is not actually incurring the costs it has projected, or some combination of the three has been occurring. (*Id*.) The Commission should also examine the following: (i) customer benefits and detriments that have resulted from the use of projected test years; (ii) conditions under which the Commission would reject the use of a projected test year; (iii) categories of expenses/revenues that are uniquely difficult to predict so as to render their inclusion in a projected test year inappropriate; (iv) minimum criteria to reasonably demonstrate a sufficient commitment by the utility to actually incur the expenses it projects; (v) length of time between the end of the historical test year and the beginning of the proposed projected test year; (vi) a method of tracking projections for various costs to determine consistency and extent of over- or under-projection and potential projection guardrails or limits; and (vii) whether the use of a projected test year by a utility should factor into its authorized ROE.

Unless and until this issue is brought under control DTE will continue to earn a rate of return higher than that authorized by the Commission to the ongoing detriment of customers. As such the Commission should take appropriate action here and reject the Company's use of projected test year expenses as a basis for its rate revenue.

B. Rate Base - Cost recovery for numerous proposed capital expenditures was not adequately supported and should be rejected.

1. Numerous proposed capital expenditures are inadequately supported.

a. Trenton Channel Sea Wall.[5]

The Company requested cost recovery of $1.427 million in the bridge period and $9.507 million in the projected test year for this project. (Exhibit A-12, Schedule B5.1.) In support of this

[5] This issue is addressed at Guillaumin 6 Tr 1624-25, 1743-45 (recommending the Commission approve the Company's proposal); York 6 Tr 3349-50 (recommending cost recovery be rejected).

request the Company provided an Appropriation Request for only $1.1 million in 2022 and 2023. (See York 6 Tr 3349-50.) This clearly does not support the level of expenditure for which the Company sought recovery here. While the Company asserted that an "appropriations request that includes the full project budget will be executed once the design and engineering is complete," this explanation does not justify recovery for costs that have not, at this time, even been the subject of an actual appropriations request. (Guillaumin 6 Tr 1744.) As such DTE has not met its burden to demonstrate cost recovery is reasonable or prudent at this time.

b. River Rouge Decommissioning (Major).[6]

The Company requested cost recovery of $33.956 million in the bridge period ($21.148 million in 2023 and $12.808 million in 2024). (Exhibit A-12, Schedule B5.1.) In support of this request DTE provided an Appropriation Request which shows expenditures of $8.4 million in 2024. (York 6 Tr 3350-51.) Consistent with this evidence the Commission should only approve cost recovery of $8.4 million as the Company has not met its burden to demonstrate the additional requested cost recovery is reasonable or prudent at this time.

c. Blackstart Projects.[7]

The Company requested cost recovery of $25.181 million related to blackstart projects, although the Company asserted it cannot disclose details regarding the same. (Exhibit A-12, Schedule B5.1.) While the Company supported this request with several Project Management and Planning ("PMP") documents, the information describing the scope and timelines for the projects

[6] This issue is addressed at Guillaumin 6 Tr 1619-20, 1627-29, 1701-04, 1739-41 (recommending the Commission approve the Company's proposal); York 6 Tr 3350-51 (recommending the Commission approve limited cost recovery).

[7] This issue is addressed at Guillaumin 6 Tr 1627-30, 1734-37 (recommending the Commission approve the Company's proposal); York 6 Tr 3351-52 (recommending the Commission reject cost recovery); Chindhade 6 Tr 4752-59 (recommending the Commission approve the Company's proposal); Decooman 6 Tr 5050-54, 5067 (recommending partial disallowances).

was redacted and the PMPs indicate they have been revised and that project schedules have changed. (See York 6 Tr 3351-52.) Due to the redactions, however, it is not possible to determine what revisions have been made, the reason for the revisions, or whether schedule changes affect the likelihood of these projects being completed as planned during the bridge period or projected test year. (*Id*.) The Company's testimony similarly provides limited information about the status of these projects, execution of project tasks, and timelines in 2023 through 2025. (*Id*.) Given this lack of supporting detail the Company has failed to meet its burden to demonstrate cost recovery is reasonable or prudent at this time. Ratepayers should not be responsible for unsubstantiated costs that have not been demonstrated to be reasonably likely to be incurred by DTE in the bridge period or projected test year and the Company cannot rely on blanket claims of information sensitivity and confidentiality to avoid the evidentiary burden set out above. The Commission should therefore reject cost recovery for these projects at this time.

d. Blackstart Peaker Unit 2 Starting System.[8]

The Company requested recovery of $2.795 million in 2025 for this project and provided redacted supporting documentation with no relevant information. (See Exhibit AB-2.) In other words, the parties and the Commission cannot review and assess the project's scope, timeline, or any revisions that may have occurred. In addition, the supporting document shows that the projected cost has changed from $50,000 to $3.245 million, without explanation. (York 6 Tr 3353.) The Company has therefore failed to meet its burden to demonstrate cost recovery is reasonable and prudent and the Commission should reject the same.

[8] This issue is addressed at Guillaumin 6 Tr 1627-30, 1734-37 (recommending the Commission approve the Company's proposal); York 6 Tr 3352-33 (recommending the Commission not approve cost recovery); Chindhade 6 Tr 4752-59 (recommending the Commission approve the Company's proposal); Decooman 6 Tr 5050-54, 5067 (recommending partial disallowances).

e. Blackstart Unit Major Overhaul.[9]

The Company requested cost recovery of $6.376 million for this project in 2025, although the supporting documents are, again, redacted and did not provide relevant information. (See Exhibit AB-2.) Again, given the lack of information the parties and the Commission cannot review and assess the project's scope, timeline, or any revisions that may have occurred. Further, the supporting document shows that a schedule change has occurred, although there is no explanation as to what the change was, why it occurred, or whether the project is likely to be complete during the bridge period or projected test year in this case. (York 6 Tr 3354.) The Company has therefore failed to meet its burden to demonstrate cost recovery is reasonable and prudent and the Commission should reject the same.

f. Blue Water Energy Center Conference Room Building.[10]

The Company requested cost recovery of $3.275 million for this project, noting that the current office space is not sufficient because the site workforce can surge in support of routine and major maintenance activities. (Exhibit A-12, Schedule B5.1.) Cost recovery for these projected expenses should again be excluded from rate base, as they were in DTE's last rate case. (York 6 Tr 3354-55.) The Company has not adequately justified the cost or the necessity of the new conference room building as it has not explained why adequate office space was not included in the original design of the Blue Water Energy Center while all of the Company's power plant facilities require such conference facilities. (*Id*.) Indeed, while the Company points to "an analysis

[9] This issue is addressed at Guillaumin 6 Tr 1627-30, 1734-37 (recommending the Commission approve the Company's proposal); York 6 Tr 3353-54 (recommending the Commission not approve cost recovery); Chindhade 6 Tr 4752-59 (recommending the Commission approve the Company's proposal); Decooman 6 Tr 5050-54, 5067 (recommending partial disallowances).

[10] This issue is addressed at Guillaumin 6 Tr 1625-26, 1699-1700, 1718-26 (recommending the Commission approve the Company's proposal); York 6 Tr 3355-56 (recommending the Commission not approve cost recovery).

of the BWEC Conference Room Building project versus other options including purchasing and renting trailers," the referenced cost assumptions (e.g., trailer rental price, labor cost, O&M, cost escalation assumptions, etc.) used in the analysis are simply inputs into an Excel model without supporting discussion or documentation. (Guillaumin 6 Tr 1726.) It's not even clear whether the analysis uses an apples-to-apples comparison of all the costs associated with a conference room compared with renting trailers or other alternatives. The Company has therefore not met its burden to demonstrate cost recovery for this project is reasonable or prudent. As such the Commission should reject the same.

2. Numerous proposed distribution capital expenditures are not adequately supported.

The Company continues to increase its distribution investment and, accordingly, its associated requested rate recovery. As shown on Exhibit A-12, Schedule B-5, distribution capital expenditure shave climbed from approximately 57.7% of total capital expenditures in 2022 to 59.8% during the bridge period and 62.7% in the projected test year. These projected capital expenditures DTE proposes to include in rate base in this case include several projects that are not projected to be placed in-service until well beyond the end of the future test year, including as far into the future as December 1, 2035. (York 6 Tr 3355-56.) Further, despite the Company's claim that this upswell in investment is aimed at improving system reliability, DTE's system reliability metrics have not significantly improved in recent years in conjunction with its increased costs. (Exhibit A-23, Schedule M-8, pp 40-41, 207-08; See Case No. U-21305, Filing Nos. 12 and 13.) Indeed, as discussed further below, the Company failed to meet its target SAIDI and CEMI4 metrics in 2023. (York 6 Tr 3356.) Given this discrepancy between the Company's investment and its results the Commission should carefully scrutinize the Company's projected costs and its request for rate recovery to ensure customer interests are being properly protected.

a. Emergent replacements.[11]

The Company requested recovery of $1.531 billion for emergent replacements based on its projections for storm, non-storm, and substation reactive investments derived from a five-year average of inflation adjustments from 2018 to 2022. (Exhibit A-12, Schedule B5.4.) As this period is inappropriate for developing a reasonable expense projection the Commission should instead approve projections based on a four-year average.

As the Company acknowledged, 2021 represented an anomalous year in which the Company experienced 12 storm events unprecedented in Company history in terms of their frequency, intensity, and customer outages. (See York 6 Tr 3357-59.) The unprecedented and significantly anomalous nature of 2021 is evident from the storm-related emergent replacements expenditures in 2021, which were more than double the Company's expenditures for 2018 through 2021 and nearly double the Company's expenditures in 2022. (Exhibit A-12, Schedule B5.4, p 3.) Further, in 2022 the number of storm days was lower than DTE projected, and there was only one catastrophic storm, which was also less than the Company's internal forecast. (*Id*.)

Data for 2021 therefore unreasonably skews the average used to project expenditures for the test period. As such the Commission should approve a four-year average of historical expenditures from 2018 to 2022, excluding 2021, as the basis for its projections of storm-related emergent replacements going forward. Again, 2021 was an unprecedented year for emergent replacements and relying on the expenditure for that year as the basis for future projections only serves to unnecessarily inflate DTE's projected capital expenditures in this case. (York 6 Tr 3358-

[11] This issue is addressed at Kryscynski 3 Tr 331-32, 334 (explaining emergent replacements); Hooper 6 Tr 2933-34 (recommending the Company's proposal); Hill 6 Tr 3034-53, 3065-87 (recommending the Commission adopt the Company's proposal); York 6 Tr 3356-59 (recommending the Commission use a four year average to project emergent replacement costs); Coppola 6 Tr 3599-617 (recommending certain cost recovery disallowances).

59.) The Company has not provided any evidence suggesting that the bridge period or projected test year will require emergent replacements that significantly exceed this four-year average. Indeed, while DTE claimed that "in 2023 the Company experienced the worst ice storm in its history along with six summer tornadoes resulting in major damage to the electric grid," its emergent replacements capital expenditures were still only $282 million in 2023, compared with $395.3 million in 2021. (Hill 6 Tr 3073.) Thus, it's claim that "a five-year historic average appropriately accounts for weather variability" is directly belied by the extraordinarily abnormal characteristics of 2021; there is simply no reason on the record to find that 2021 data is at all reflective or useful for anticipating 2025 expenses. (Hill 6 Tr 3072-73.) As such the Commission should reject the use of 2021 data in projecting the Company's test year emergent replacement costs and approving recovery of the same. Further, the inflation adjustments used to project emergent replacements (and all base capital expenditures) should be updated to reflect the Real GDP Chained Price Index, as discussed in more detail below. Adopting this recommendation will reduce the Company's total proposed base capital expenditure amount by $122.882 million. (York 6 Tr 3358-59.)

b. Strategic replacements.[12]

The Company projected $2.337 billion for strategic capital programs, including some projects which are not expected to be placed in service until after the end of the projected test year

[12] This issue is addressed at Kryscynski 3 Tr 329-61, 401-14, 433-38, 472-87, Hartwick 4 Tr 837-38, 857, Elliott Andahazy 4 Tr 908, 1024-28, 1065, Deol 5 Tr 1268, Hatsios 6 Tr 2192-95, Steudle 6 Tr 3001-71 (recommending the Commission approve the Company's proposal); York 6 Tr 3359-61 (recommending the Commission approve cost recovery for only the projected capital expenditures associated with projects that are expected to be in-service during the bridge period and projected test year); Alvarez 6 Tr 3928-98 (recommending certain cost disallowances); Dufree 6 Tr 5155-57 (reviewing the Company's proposals).

in this case. (Exhibit A-12, Schedule B5.4, p 1.) As cost recovery for these expenditures is unreasonable at this time the Commission should reject the same.

There are a number of flaws with the Company's request for such significant cost recovery related to these projects. First, as noted above, while DTE has increased strategic capital program spending to improve system resiliency and reliability, its system reliability metrics have only minimally approved. (See York 6 Tr 3359-61.) In other words, the Company's cost recovery and rate increases for this issue have not produced correspondingly improved service. As such cots recovery is neither reasonable nor prudent.

Further, the Company has a history of underspending on strategic capital programs relative to its projections and instead diverting those funds to emergent replacements. (See *Id*. (internal citations omitted).) In addition, DTE's proposed spending on these programs includes significant levels of capital expenditures for projects that are not expected to be placed in-service until after the end of the projected test year in this case. (Exhibit A-12, Schedule B5.4, pp 8-12.) Specifically, the Company's documentation shows that several projects are expected to be in-service at various dates ranging from December 31, 2026 through December 31, 2035, and therefore will not become used and useful during the bridge period or projected test year. (*Id*.)

Given the Company's minimal improvement in system reliability metrics, the fact that cost recovery for these projects has been historically diverted to other cost categories, and the fact that many expenditures are for projects which may not enter service until well beyond the test year, the Commission should only approve cost recovery for the projected capital expenditures associated with projects that are expected to be in-service during the bridge period and projected test year. While this would result in including $1.723 billion of capital expenditures for strategic capital programs in the Company' rate base, which is a reduction of $613.586 million relative to the

amount proposed by the Company, it is still roughly 2.5x the amount reportedly spent in 2022. (York 6 Tr 3360.)

C. Capital Structure and Rate of Return – A reasonable ROE for the Company is 9.6%.[13]

A utility's cost of common equity is the expected return that investors require on an investment in the utility. (Walters 6 Tr 3441-43.) 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 as well as the Company's specific circumstances its ROE should be set at no higher than 9.6%.

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 requested a 10.5% ROE. (See Villadsen 6 Tr 2489-535.) Because this proposal is inconsistent with utility industry trends, access to capital, and credit strength it should be rejected.

[13] This issue is addressed at Villadsen 6 Tr 2407-535 (recommending a 10.5% ROE); Walters 6 Tr 3421-504 (recommending a 9.6% ROE); Coppola 6 Tr 3658-83 (recommending a 9.85% ROE); Bandyk 6 Tr 3743-61 (recommending a 9.3% ROE); Stults 6 Tr 4252-56 (recommending the Commission consider a lower ROE); Koeppel 6 Tr 4437-40 (recommending a 9.18% ROE); Perry 6 Tr 4726-34 (recommending the Commission consider a lower ROE); and Ufolla 6 Tr 5013-27 (recommending a 9.9% ROE).

While the Company recommended an increase above its current ROE, authorized ROEs for regulated utilities have declined over the last ten years and have been reasonably stable below 10.0% for roughly the last nine years (specifically the majority of authorized ROEs since 2016 have been below 9.7%, with many being below 9.5%).[14] (Walters 6 Tr 3424-31.) During that time the utility industry's common equity ratios have also not deviated too much from the range of 50.0% to 52.0%. (*Id*.)

Further, since 2009 industry credit ratings have continued to improve.[15] (*Id*.) As explained in a recent Regulatory Research Associates' Report "[m]ultiple drivers are expected to elevate utility capital expenditures over the next several years," spending "expectations for 2024 and beyond are likely to increase," and utilities "have multiple opportunities to finance and support energy investments through mechanisms available within the Inflation Reduction Act and the Infrastructure Investment and Jobs Act of 2021." (*Id*. (internal citation omitted).) Indeed, capital expenditures for electric and natural gas utilities have increased considerably over 2023 into 2024,

[14] 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." *In the Matter of the Application of DTE Energy Co*, order of the Public Service Commission, entered April 18, 2018 (Case No. U-18255), p 20; see also *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 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"); *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered December 17, 2020 (Case No. U-20697), p 165 (noting "current market trends" and "national average" ROEs in explaining its decision, as well as the "fact that other utilities have been able to access capital despite lower ROEs, which "is also a relevant consideration").

[15] The Company's claims that the "fact that DTE Electric has maintained its credit rating and is able to attract debt capital does not imply that the allowed ROE is commensurate with returns on investments in other enterprises having corresponding risks" are inaccurate. (Villadsen 6 Tr 2530-31.) A company with a higher credit rating will have more access to capital at better terms and prices than another company with a lower credit rating all else equal. To suggest that credit ratings have no impact on the cost of equity is completely unfounded.

and forecasted capital expenditures remain elevated through the end of 2025. (*Id*.) Thus, capital investments for the utility industry continue to stay at elevated levels and are expected to fuel utilities' profit growth into the foreseeable future. (*Id*.) Capital investments are therefore enhancing utility shareholder value and attracting both debt and equity capital to the utility industry. Of course, while capital markets embrace these profit-driven capital investments, regulatory commissions must protect customers' need for reliable utility service at reasonable rates. (*Id*.) Without doing so utility rates will eclipse customers' ability to pay, resulting in revenue constraints for utilities which will 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, meaning they can access equity capital under reasonable terms and conditions and at relatively low cost. (*Id*.) Indeed, 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*.) Thus, authorized returns on equity, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the global pandemic. Considering this consistent success and future expectations it is critical that the Commission ensure utility rates are increased no more than necessary to provide fair compensation and maintain adequate financial integrity. In other words, while capital markets embrace utilities' profit-driven capital investments and reward shareholders, the Commission must be careful to maintain reasonable and affordable customer rates.

The utility industry's relatively strong financial position is further buttressed by the federal reserve's efforts to support the economy to achieve maximum employment and manage long-term inflation at around a 2% level. (Walters 6 Tr 3431-37.) Specifically, the federal reserve has

implemented procedures to support the economy's efforts to achieve these policy objectives, including lowering the Federal Overnight Rate for securities and again engaging in a Quantitative Easing program to moderate the demand in the marketplaces and support the economy. (*Id*.) The federal reserve is currently reducing its holdings of Treasury securities, agency debt, and agency mortgage-backed securities. (*Id*.) All of these actions are known by market participants due to federal reserve transparency and the market's reaction has resulted in the Federal Funds Rate far outpacing the rise in utility and treasury yields, while the spread of utility bonds over treasury bond yields has recently stabilized. (*Id*.) The Fed has also noted that it has had some success reducing inflation growth and has reiterated its commitment to stabilizing consumer prices and promoting maximum employment through its monetary policy tools. (*Id*. (internal citation omitted).)

In terms of interest rates, short-term projections suggest that while the market expects current capital costs to increase at mixed rates, they will maintain levels that are still low by historical standards. (*Id*.) Specifically, while the federal funds rate will increase at a much faster rate than long-term interest rates as measured by the 30-year Treasury bond, inflation is expected to lessen in the near to intermediate term. (*Id*.) The outlook for long-term interest rates in the intermediate to longer term has indicated potential increases relative to 2020 and 2021, although they are still relatively modest compared to time periods prior to the beginning of the worldwide pandemic. (*Id*.) Thus, relatively low capital market costs are expected to prevail at least in the near-term and out over the next five to ten years. (*Id*.) Further, while there is potential for some upward movement in the cost of capital, that upward movement is not guaranteed, as previous increases in the Federal Funds Rate have not necessarily translated into increases in longer term yields. (*Id*.)

While this indicates a positive environment for utilities, credit rating agencies analyses have stressed that rate affordability is an important consideration in assessing utility credit. For

instance, Moody's recently explained that regulated utilities' outlook remains "Negative" largely due to increased pricing pressures on customers, specifically explaining that the outlook was due to "increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates," which developments "raise residential customer affordability issues, increasing the level of uncertainty with regard to the timely recovery of costs for fuel and purchased power, as well as for rate cases more broadly." (Walters 6 Tr 3437-40 (internal citation omitted).) Similarly, in a January 2024 report, S&P specifically mentioned commodity price volatility, in combination with significant increases in capital investments, driving utility rate increases which may strain affordability concerns. (*Id*. (internal citation omitted).) Finally, Fitch recently noted bill affordability concerns for ratepayers and regulators' ability to balance the rate requests with increasing customer bills. (*Id*. (internal citation omitted).) Thus, credit analysts have focused on rate affordability as an important factor to support strong credit standing. Customers must be able to afford their utility bills in order for utilities to maintain their financial integrity and strong investment grade credit standing.

Lastly, while in 2023 the utility sector underperformed the S&P 500, and has continued to do so in 2024, the performance of the S&P 500 has largely been driven by a handful of "mega cap" companies. (Walters 6 Tr 3440-41.) Thus, despite its recent underperformance relative to the S&P 500, the utility industry has still been able to deliver generally positive and relatively stable returns during a period of elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world. (*Id*.) As such this underperformance is misleading and does not demonstrate volatility of utility credit metrics, or a basis for an elevated ROE.

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. It is instead

imperative that utility rates reflect the relative stability of utility performance contrasted with the impact of increasing rates on customers. The Company's proposed increase in its ROE should therefore be rejected and the Commission should instead approve a ROE of no higher than 9.6%.

2. The Company's risk and reasonably applied empirical analyses demonstrate that DTE's ROE should be set at no higher than 9.6%

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

The Company's risk is best described by credit rating analysts' reports. (Walters 6 Tr 3443-45.) DTE's current corporate bond ratings from S&P and Moody's are A- and A2 respectively and its outlook from both S&P and Moody's is "Stable." (*Id*. (citation omitted).) Specifically, S&P stated that DTE's business risk 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." (*Id*. (internal citation omitted).) The Company "benefits from a constructive and supportive regulatory framework in Michigan that supports forward looking rate cases and various riders that enhance cash flow predictability." (*Id*. (internal citation omitted).) Further, "the predominance of residential and commercial customers restricts susceptibility to economic cyclicality and provides more stable operating cash flow." (*Id*. (internal citation omitted).) Thus, S&P expects DTE's "financial measures to remain in the significant range of financial risk profile." (*Id*. (internal citation omitted).)

In short, the Company has strong credit ratings resulting from lower risk utility operations and benefitting from constructive credit support mechanisms and Michigan's existing regulatory framework. This indicates the Company has minimal risk and does not require a ROE above what the Commission has previously approved.

b. The Company's proposed capital structure relative to a reasonable proxy group demonstrates the unreasonableness of its ROE request.

The Company's proposed equity ratio significantly exceeds that for the proxy group the Company used to support its ROE recommendation. (See Walters 6 Tr 3445-46; see Exhibit AB-5.) Thus, the Company's proposed equity ratio and ROE are diametrically contrary to additional regulatory commissions' recognition of the importance of aligning the cost of equity with capital structure. (*Id*. (internal citations omitted)). As described in more detail below, while ABATE's proxy group in this case had an average common equity ratio of 40.9% (including short-term debt) and 44.5% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively, DTE's proposed ratemaking equity ratio of 50% (excluding short-term debt) exceeds that of the proxy group's equity ratio and is not reasonable for ratemaking purposes. (*Id*.)

The Company's proposed equity ratio therefore significantly exceeds the equity ratios of the proxy group. As such the Commission should, consistent with its prior Orders, approve a correspondingly lower ROE.

c. 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 6 Tr 3446-47.) The proxy group utilized for ABATE's quantitative analyses is the same as that utilized by DTE and has average credit ratings of BBB+ and Baa2 from S&P and Moody's, respectively. Thus, the proxy group's average rating of BBB+ from S&P is one notch lower than DTE's rating of A- from S&P, and the proxy group's average rating of Baa2 from Moody's is three notches lower than DTE's rating of A2. (*Id*.) Despite these ratings, DTE selectively noted certain purported risks to claim it was risker than the proxy companies with lower credit ratings. (See Walters 6 Tr 3493-94.) These claims should

be ignored as they are objectively belied by the actual credit ratings for the Company and the proxy group. Indeed, to the extent rating agencies deem the particular purported risks claimed by DTE to be detrimental, they would already be taken into consideration and reflected in DTE's credit ratings. (*Id*.)

Again, DTE's ratings from both S&P and Moody's are higher than those of the proxy group. S&P and other credit rating agencies go through great detail in assessing a utility's business and financial risk in order to evaluate their assessment of its total investment risk. (*Id*.) Thus, given the ratings set out above, if anything DTE's total risk is demonstrably less than that of the proxy group. Further, as explained below concerning the Capital Asset Pricing Model ("CAPM"), investors are not compensated for taking on company-specific risks, as those risks can be eliminated through portfolio diversification. (*Id*.) Institutional investors are the largest holders of utility stocks in general and DTE's implication that these sophisticated investors are not well-diversified and somehow need to be compensated for taking on company-specific risks would be an error in violation of the underlying premise of the CAPM. (*Id*.) The Company's suggestion that DTE is of higher risk relative to the proxy companies is therefore unfounded and should be disregarded.

The proxy group also has an average common equity ratio of 40.9% (including short-term debt) and 44.5% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. (Walters 6 Tr 3446-47.) Thus, DTE's requested equity ratio far exceeds the proxy group's equity ratio. These differences in credit ratings and equity ratios indicate DTE's cost of equity capital is mostly likely to be below the midpoint of the cost of equity range indicated by the proxy group results.

d. Reasonable empirical models demonstrate a reasonable ROE for the Company is 9.6%.

In developing a reasonable ROE for the Company ABATE witness Chris 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 DCF model; (iv) a Risk Premium Model; and (v) a CAPM. Considering DTE's specific risk and the result of these analyses a reasonable ROE is 9.6%.

i. Constant growth DCF Model.

The 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 6 Tr 3448-52.) 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 June 21, 2024. 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. (*Id*.) The dividend used was each proxy company's most recently paid quarterly dividend as reported in *Value Line*. (*Id*.) 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 have been shown to be more accurate than growth rates derived from historical data. (*Id*.) Thus, ABATE's growth rate relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. (*Id*.) The specific growth rates used are shown in Exhibit AB-6. The average and median growth rates for the proxy group are 6.29%. As shown in

Exhibit AB-7, the average and median constant growth DCF returns for the proxy group for the 13-week analysis are 10.43% and 10.51%, respectively.

It should be noted, however, that the proxy group average three- to five-year growth rates are approximately 50% higher than the long-term projected GDP growth rate of 4.24%.[16] (*Id*.) This makes these ROE estimates higher than is likely reasonable as a utility's growth 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*.) In other words, these model results are likely unreasonably high.

ii. Sustainable growth DCF.

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 the rate base. (Walters 6 Tr 3452-53.) Thus, 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-8. 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.[17] (*Id*.) As shown in

[16] *Blue Chip Financial Forecasts* projects a U.S. nominal GDP growth rate of 4.24% over the next 5 and 10 years. (Walters 6 Tr 3451 (internal citations omitted).) 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*.)

[17] The Company claimed that ABATE witness Christopher Walters' sustainable growth model suffers from reliance on only one source for its growth rates (*Value Line*) and that the expected ROE as forecasted by *Value Line* averages 11.13 percent, while Mr. Walters calculated an average ROE of 9.10 percent. (Villadsen 6 Tr 2056.) Despite this claim, DTE failed to provide sources

Exhibit AB-9, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 5.02% and 4.95%, respectively. A DCF estimate based on these sustainable growth rates is developed in Exhibit AB-10 and produces proxy group average and median DCF results for the 13-week period of 9.10% and 9.03%, respectively.

iii. Multi-stage growth DCF model.

The DCF model is intended to represent the present value of an endless series of future cash flows. (Walters 6 Tr 3453-59.) Thus, in addition to the analyses described above, to accommodate changing growth expectations over time as investments slow or plateau, it is 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 the current market conditions, industry trends, and determining whether the three to five-year growth outlook is feasible and sustainable. (*Id*.)

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. (*Id*.) Again, utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. (*Id*.) 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

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other than *Value Line* which have estimates for each of the components used in the model and overlooked the financial texts in support of the sustainable growth (also known as retention growth) model. As such the Company's objection is unreasonable and should be rejected.

nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility. As shown in Exhibit AB-11, the average and median DCF ROEs for the proxy group using the 13-week average stock price and appropriate growth rate projections are 8.83% and 8.90%, respectively. (*Id*.) Again, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate which is approximately 50% higher than the long-term projected GDP growth rate of 4.24%. (*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.

iv. Risk premium model.

This model is based on the principle that investors require a higher return to assume greater risk. (Walters 6 Tr 3459-63.) 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;[18] 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.[19] (*Id*.; Exhibits AB-12, AB-13, and AB-14.)

[18] The risk premium was estimated on an annual basis for 1986 through 2023. (Walters 6 Tr 3459-63.) The authorized ROEs were based on regulatory commission-authorized returns for utility companies. (*Id*.) Authorized returns are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding. (*Id*.)

[19] The period of 1986 through 2023 was used because public utility stocks consistently traded at a premium to book value during that period. (*Id*.; Exhibit AB-12.) The market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. (*Id*.) Over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value. (*Id*.) This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. (*Id*.) It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders. (*Id*.)

Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology. (*Id*.) The risk premium model therefore assessed the five-year and ten-year rolling average risk premiums[20] over the study period to gauge the variability over time of risk premiums. (*Id*.) These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle.[21] (*Id*.)

The Company's critique that ABATE's analysis "fail[ed] to take into account the inverse relationship between the utilities' equity risk premium and the level of interest rates" because "as interest rates increase (decrease), the equity risk premium decreases (increases), so the risk premium is not constant over time" is baseless. (Villadsen 6 Tr 2513-14.) As shown on Exhibit AB-13, Line 38, the indicated equity risk premium in 2023 for Electric Utilities was 5.57% when the 2023 average 30-year Treasury yield was 4.09%. As shown on Line 39, the 2024 average 30-year Treasury yield has been 4.33%, with an indicated equity risk premium of 5.33%. This indicates that, if anything, ABATE's assumed equity risk premium of 5.70% *overstates* the cost of equity, contrary to DTE's contrary assertion.

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[20] This time period is the most appropriate to make reliable determinations about contemporary market conditions because contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. (*Id*.) A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized ROEs and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. (*Id*.) Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. (*Id*.) While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums. (*Id*.)

[21] Further market evidence was also used when developing the risk premium analysis. (*Id*.) Because the equity risk premium should reflect the market's perception of risk in the utility industry today, Exhibit AB-15 gauges investor perceptions in utility risk today, which shows the yield spread between utility bonds and Treasury bonds since 1980.

The risk premium result from the method described above and using a projected 30-year Treasury yield of 4.30% is 10.00%. Similarly, using 13-week and 26-week periods, the results are 10.05% and 9.95% using A-rated utility bonds, respectively. (Walters 6 Tr 3459-63.)

v. 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 6 Tr 3463-77.) 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. (*Id*.) According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. (*Id*.) Thus, 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 beta used in ABATE's analysis was based on the current proxy group average and median *Value Line* beta estimates (*Id*.; Exhibit AB-17.) Because these beta estimates are abnormally high and are unlikely to be sustained over the long-term, however, the analysis also considered the historical average of the proxy group's *Value Line* betas and included adjusted beta estimates as provided by Market Intelligence's Beta Generator Model, which relied on a five-year period on a weekly basis ending June 1, 2024.[22]

[22] Again, historical betas provide context for the significant extent to which current betas are anomalous and were required to provide a more normalized estimate of the beta component for the

(*Id*.) 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. (*Id*.) 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. (*Id*.)

As shown in Exhibit AB-18, the results of nine different applications of the CAPM range from 8.85% to 12.27%. (*Id*.) Because current beta estimates are based on the most recent five years of historical stock returns and volatility, however, they are still heavily impacted by the market fallout in early 2020. (*Id*.) As such, it is appropriate to give primary consideration to the results of a CAPM analyses using long-term average *Value Line* betas. Considering this weighting an appropriate average of the CAPM results is 9.51%.

vi. A reasonable ROE for the Company should be no higher than 9.6%.

Based on these analyses, an appropriate estimate for the Company's current market cost of equity is within the reasonable range of 9.20% to 10.00%. (Walters 6 Tr 3478.) This recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model, the irrational assumption that *Value Line*'s current beta estimates are reflective of current investor expectations, and the unsustainable growth rates assumed in the DCF-derived expected market

CAPM analysis. (Walters 6 Tr 3463-77.) For this reason Staff's CAPM analysis, which was based on five-year betas that are not representative of current market conditions, perceived risk of regulator utilities, or investor expectations, must also be rejected. (Walters 6 Tr 3501-04.) The Company's claim that historic betas are "not relevant" because "it is imperative that betas reflect the best current estimate of the systematic risk" is therefore similarly flawed. (Villadsen 6 Tr 2509.) The Company's disregard of historic averages skews its ROE analysis in favor of betas influenced by more recent anomalous occurrences unlikely to be repeated in the test year and should be rejected. In other words the beta used by the Company does not reflect current systematic risk and instead operates to inflate DTE's proposed ROE.

return for the CAPM. Based on an objective assessment of DTE's overall risk profile and the results of these analytical methods, an appropriate ROE for DTE is 9.6%, which is the midpoint of the range produced by these models. (*Id*.)

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

The Company requested a 10.5% ROE based on its perception of DTE's risk and several models which it applied to its proxy group. Those models included a traditional CAPM and an empirical CAPM ("ECAPM"), a simple DCF, a multi-stage growth DCF, and a risk premium model. (Villadsen 6 Tr 2414-15.) As this ROE is excessive and unreasonable given DTE's actual risk and the flaws in DTE's analyses the Commission should reject the Company's request.

Reviewing DTE's model ROE results applied to its proxy group indicates the Company's perception of its required ROE is in the range of 8.7% to 11.1%. (Walters 6 Tr 3479-82.) Despite this range, DTE increased its market ROE estimate by adjusting its results upward in the range of 0.4%-1.1% using an overall cost of capital ("OCC") methodology. (*Id*.) The OCC method is identical to the After-Tax Weighted Average Cost of Capital ("ATWACC") methodology previously rejected by the Commission in multiple DTE rate cases. This ATWACC adjustment increased the Company's recommended range up to 10.25%-11.0%. (*Id*.) Without this improper adjustment DTE's own studies, with reasonable adjustments, would support a ROE of 9.60%, consistent with ABATE's recommendation.

The Company calculated an ATWACC for each of its sample DCF results by using each sample company's market value capital structure and assuming cost rates for the cost of debt and preferred stock based on each company's credit rating. (Walters 6 Tr 3482-85 (internal citation omitted).) The Company also assumed DTE's composite tax rate of 25.7% is applicable to all companies in its sample. After calculating the OCC, or ATWACC, the Company then backed into the ROE required to produce the same rate of return using DTE's book value capital structure and

embedded cost of debt. (*Id*.) This methodology is unreasonable and does not produce a reliable ROE estimate.

The first problem with this method is that DTE's common stock is not publicly traded and does not have a market value capital structure, meaning it does not provide a basis of comparison with the proxy companies' stocks. (*Id*.) Further, the ATWACC is generally poor regulatory policy. First, this measure does not produce clear and transparent objectives for management to minimize DTE's overall rate of return while preserving its financial integrity. (*Id*.) Thus, it does not consider a utility's need for capital discipline as it effectively treats it as an unregulated utility affiliate. Under the ATWACC theory, management decisions regarding capital structure can be skewed by changes in market value, which change the market value capitalization mix. The Company's management, however, has no control over the market value capital structure, although it does have control over the book value capital structure. (*Id*.) Setting the rate of return and measuring risk based on book value capital structure therefore creates a more transparent and straightforward path for regulatory oversight of management's effort to maintain a balanced and reasonable capital structure. This is particularly true in this context, where the Commission cannot oversee the reasonableness and prudence of Company management's decisions to manage DTE's capital structure. The Company's alternative approach is therefore unreasonable.

In addition, the ATWACC introduces significant additional instability and unreliability into the utility's cost of service and tariff rates. (*Id*.) Book value capital structure weights permit the utility to hedge or lock-in a large portion of capital market costs in arriving at the rate of return used to set rates, which rate of return cost hedge stabilizes the utility's cost of service, which in turn helps stabilize utility rates. This stable method of setting rates also allows investors to more accurately assess the utility's future earnings and cash flow outlooks, which will reduce business

risk. (*Id*.) By contrast, the ATWACC produces an overall rate of return which will change based on both changes to market value capital structure weights and market capital costs. (*Id*.) Thus, a major component of the Company's cost structure (i.e., the overall rate of return) would vary based on market forces from rate case to rate case, which variability will result in significant instability in the utility's cost of service (via rate of return changes) and instability in tariff rates. (*Id*.) There is no benefit to ratepayers or investors in introducing additional instability and unreliability into DTE's cost structure. The Company's approach to using an ATWACC to estimate a ROE recommendation is therefore unreasonable.

Finally, the ATWACC artificially increases rates to produce an excessive ROE for the benefit of utility investors, as if the utility were an unregulated affiliate. Inflating utility rates to provide this excessive earnings opportunity at ratepayer expense is unjust and unreasonable and should be rejected. The flaws in this method have been previously recognized in this same context. (See Case No. U-18999, Proposal for Decision, July 16, 2018, p 77 ("DTE Gas's ECAPM analysis, and its ATWACC adjustment, result in unreasonable and inflated ROE estimates"); Case No. U-20561, Proposal for Decision, March 5, 2020, p 301 ("Notwithstanding Dr. Villadsen's testimony asserting that the empirically-determined adjustments *Value Line* betas do not duplicate the empirically-determined ECAPM alpha-values, this PFD finds . . . that the two adjustments are duplicative").) Indeed, in Commission has previously agreed that "that little or no weight should be given to the utility's ATWACC calculations." *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 66. This same finding has been made in additional jurisdictions. (See Walters 4 Tr 1396-97 (internal citations omitted).) These Commission and ALJ decisions have also been echoed in additional jurisdictions, such as Illinois. (*Id*. (internal citations omitted).)

The ATWACC is therefore inappropriate for determining a reasonable ROE for DTE. As such the Commission should rejected the Company's analysis as well as the recommended ROE based thereon.

a. The Company's DCF analysis is also flawed.

In addition to the faulty financial adjustments described above, the Company's DCF analyses contained further flaws and should be rejected. (Walters 6 Tr 3485-86.) First, the Company artificially removed what it deemed to be low-end outliers, but not high-end outliers. (*Id*.) For instance, the Company removed the results for two proxy companies for being purportedly too low, while including the results of another entity which were 16.7%. (*Id*.)

DTE's recommendation also placed too much weight on the results of its constant growth DCF analysis without adequately considering its multi-stage DCF results. The average growth rate of the Company's electric sample is 6.24% and is assumed in perpetuity in DTE's constant growth model. (*Id*.) This growth rate exceeds DTE's projected growth rate of 4.24% for the US economy by approximately 47%. Such a growth rate is clearly unsustainable and defies economic logic as explained above.

A more reasonable estimate of DTE's DCF analysis would be the median of its unadjusted results (excluding the results of one entity) of 8.7% (multi-stage DCF) and 10.15% (constant growth DCF), or 9.4%. (*Id*.) The Company's alternative approach is unreasonable and should be rejected.

b. The Company's CAPM and ECAPM analyses are overstated.

The Company's analysis proposed a financial risk adjustment to reflect a leveraged beta adjustment which added approximately 60 basis points to the base CAPM return estimates. (See Walters 6 Tr 3486-91.) As explained above the Company has greatly overstated its risk contrary to the analyses of credit rating agencies and comparable proxy companies. As this leverage

adjustment to the base CAPM return estimate produced an excessive and unreasonable ROE for DTE it should be rejected.

First, the Company's *Value Line* betas are still being impacted by the market fallout caused by the pandemic in early 2020, meaning they are not reflective of current investor expectations. (*Id*.) As noted above, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. Thus, it is necessary to consider the historical average of the proxy group's *Value Line* betas.

Further, DTE's risk free rate was based on stale data and assumed the 20-year yield will equal the 30-year yield. Using more recent data, a more reasonable estimate of the projected 20-year Treasury yield would be between the projected yields for the 10-year Treasury (4.0%) and the 30-year Treasury (4.3%). (*Id*.) The midpoint of these figures is 4.15%, compared with DTE's projected 4.3%. (*Id*.)

As explained above, the market risk of utility stocks has declined subsequent to the global pandemic and market fallout, meaning betas based on five years of prices and volatility unreasonably overstate the cost of equity in a CAPM analysis. (*Id*.) A beta based on prices and volatility after the peak impact of the pandemic, such as one that uses three years of prices and volatility, is more reasonable. Incorporating such a beta (0.72) into DTE's analyses reduces its CAPM results to 9.46% when using DTE's 7.17% risk premium, or 8.89% using DTE's 6.37% market risk premium. (*Id*.)

In addition, as an alternative to the ATWACC adjustment described above, the Company also measured an additional ROE adjustment based on leveraged adjustments to the beta component of the CAPM study. (*Id*.) In producing this adjustment, DTE utilized the Hamada method to de-lever and re-lever the beta component in both the CAPM and the ECAPM with and

without the effect of income taxes. (*Id*.) Doing so increased the already inflated Full Sample *Value Line* beta from 0.88 to 1.04 (with and without taxes) for the electric sample. (*Id*.) Thus, the Hamada model produced CAPM results in the range of 10.9% to 11.7% and ECAPM results in the range of 10.8% to 11.7% for the electric sample. (*Id*.) These financial leverage adjustments are generally not accepted in establishing a fair ROE in regulated rate-setting proceedings and should be rejected here.

The Company's ECAPM return estimates are also flawed. Specifically, DTE included an adjusted beta within its ECAPM studies which is inconsistent with the academic research supporting the development of an ECAPM methodology. (*Id*.) Doing so double counts the purpose of the ECAPM study and has the effect of both increasing CAPM return estimates for companies with betas less than 1 and decreasing the CAPM return estimates for companies with betas greater than 1. (*Id*.) Incorporating this adjustment when using an already-adjusted beta such as those published by *Value Line* also improperly makes the same adjustment twice. (*Id*.) Thus, in effect, applying these adjustments to already-adjusted betas results in a double adjustment which skews the analysis' results. Thus, the ECAPM using a raw beta, and an ECAPM using a *Value Line* beta, have a magnified effect. (*Id*.) As there is no legitimate basis for using an adjusted beta within an ECAPM, because they are both designed to produce the same effect on the CAPM return estimate, the Commission should reject the Company's analysis and the ROE recommendation based thereon.

c. The Company's risk premium analysis is also flawed.

The Company used its projected risk-free rate of 4.3% and a regression-derived risk premium estimate of 6.3% which resulted in a ROE estimate of 10.4%. (Walters 6 Tr 3492-93.) Both the projected risk-free rate and projected risk premium are too high and this analysis should be disregarded.

Similar to its CAPM analysis, the Company's projected risk-free rate of 4.3% is based on an outdated projected 10-year Treasury yield of 3.80% plus a 0.50% point spread to account for differences between the 20-year yield over the 10-year yield. (*Id*.) More recent projections of the 10-year yield are 4.0%, while the most recent projection for the 30-year yield is 4.3%. Thus, a more reasonable assumption for the 20-year yield is the midpoint between the projected 10 and 30-year yield, or 4.15%. (*Id*.) Further, the authorized ROE equity risk premium has recently been average or below, meaning DTE's assumption of an equity risk premium significantly above average is irrational and unreasonable. An average equity risk premium and more recent estimates of Treasury bond yields produces a cost of equity estimate of 10.0%. (*Id*.) As such the Company's risk premium analysis is unreliable and the recommended ROE based thereon should be rejected.

4. Staff's ROE analysis is also flawed and should be rejected.

In addition to its flawed CAPM analysis based on five-year betas, as described above, Staff's 9.9% ROE recommendation is unexplainably at the high-end of its recommended range of 9.30% to 10.30% and is inconsistent with Staff's recommendation in DTE's pending gas rate case (Case No. U-21291). (See Walters 6 Tr 3502-05.) As such the Commission should reject Staff's recommended ROE.

In Case No. U-21291 Staff presented the same recommended ROE range of 9.3% to 10.3% yet recommended a 9.8% ROE for DTE Gas. (See Case No. U-21291, Filing No. 304 at 18.) Here, despite having the same recommended range and both DTE Gas and DTE Electric currently having the same 9.9% ROE, Staff has inexplicably recommended a higher ROE for the Company. There is no reason for recommending a higher ROE above the midpoint of Staff's recommended range in this case, particularly as that recommended range is already overstated.

Here, the high-end of Staff's range (10.30%) is based on the results of its CAPM analysis which range from 10.23% to 10.31%. (*Id*.) As explained above, current *Value Line* beta estimates

are based on five years of historical prices and volatility, meaning they are still heavily impacted by the market fallout from the global pandemic in early 2020. Betas based on five years of data are therefore not representative of investor expectations, current market conditions, or perceived market risk of regulated utility companies. (*Id*.) As shown in Staff's Exhibit S-4, Schedule D-5, its average proxy group beta is 0.94 and ranges from 0.80 to 1.15. This range unrealistically assumes that utilities are approximately as risky as the market, on average. Again, measuring betas after removing the impact of the global pandemic results in utility betas of approximately 0.72 under *Value Line*'s adjustment methodology. (*Id*.) This level of beta is in-line with long-term averages and more reasonably reflects the current market risk.

Assuming Staff's risk-free rate of 3.85% and market risk premium of 6.80, its CAPM results would be lowered from 10.23% to 8.75%. (*Id*.) The midpoint of this range is 9.47%, which is nearly 100 basis points lower than its recommended high-end range figure of 10.3%. Given the flaws in Staff's analysis its ROE recommendation based thereon should be rejected.

D. Adjusted Operating Income - The Company's proposed O&M expense is unreasonable and should be rejected.

1. The inflation factor used in the Company's analysis is unreasonable.[23]

The Company projected its O&M expense would increase $42.513 million, or about 3.5%, in the projected test year as a result of $85.549 million of inflation adjustments offset by a $44.037

[23] This issue is addressed at Foley 6 Tr 172-78, Kryscynski 3 Tr 321-22, Uzenski 6 Tr 1497, Hatsios 6 Tr 2299, Wisniewski 6 Tr 2837-38, and Hill 6 Tr 3035, 3043-45, 3065-80 (recommending the Company's proposed inflation factors); York 6 Tr 3335-42 (recommending alternative inflation factors); Coppola 6 Tr 3598-99, 3683-86 (recommending alternative inflation factors); Bandyk 6 Tr 3741-42 (recommending alternative inflation factors); McMillan-Sepkoski 6 Tr 4926-27, Rueckert 6 Tr 4995, and Rogers 6 Tr 5186 (recommending alternative inflation rates for certain cost categories).

million credit for Other Adjustments. (Exhibit A-13, Schedule C5.) As this inflation adjustment is significantly overstated the Commission should reject the Company's request.

First, despite DTE's use of projections for 2023, actual costs are now available and the Commission's decision should not be based on a composite adjustment reflecting a 3.20% inflation factor and a 3.0% wage adjustment, which overstates DTE's actual costs. (York 6 Tr 3335-42.) Specifically, DTE projected inflation adjustments for 2023 of $29.869 million which, when added to DTE's actual 2022 historical O&M expense yields a projected O&M expense of $1.254 billion. (*Id*.) The Company's actual O&M expense for calendar year 2023, however, was only $1.197 billion, meaning DTE's projected 2023 O&M expense was overstated by $56.420 million. (*Id*.) Thus, to be conservative, the Commission should resolve the discrepancy between DTE's actual and projected O&M expense for 2023 by eliminating DTE's proposed inflation adjustment for 2023.

Further, DTE's projected inflation adjustments from 2023 through December 2025 result in average annual O&M expense increases significantly greater than the annual O&M expense change DTE has actually experienced over the last five years. (*Id*.) Specifically, DTE's projected inflation adjustments for 2024 and 2025 are $27.935 million and $28.745 million, respectively, which reflect composite factors based on a combination of inflation measured by the CPI (2.4% in 2024, and 2.2% for 2025), and a 3.0% annual wage escalation factor. (*Id*.) In total, DTE's projected 2024 O&M expense therefore reflects an approximately 7.0% increase over the 2023 actual O&M expense, while DTE's projected 2025 O&M expense reflects an approximately 2.2% increase over the 2024 projected O&M expense. (*Id*.) Both of these projected increases significantly exceed DTE's actual average annual increase in O&M expense over the last several years. (*Id*.)

Contrasted with these projected increases, the Company's actual annual O&M expense increased by an average rate of only 1.4% per year from 2017 to 2022, while the adjusted O&M expense (which reflects ratemaking and normalization adjustments) decreased by an average rate of 0.2% per year (*Id.*):

TABLE JAY-2

Historical Changes in O&M Expense ($000)

Line	Calendar Year	Actual Historical Test Period O&M[1] (1)	Annual Change (2)	Adjusted Historical Test Period O&M[1] (3)	Annual Change (4)
1	2017	$1,426,289		$1,234,078	
2	2018	1,463,066	2.6%	1,269,157	2.8%
3	2019	1,440,617	-1.5%	1,260,934	-0.6%
4	2020	1,495,522	3.8%	1,258,887	-0.2%
5	2021	1,561,797	4.4%	1,290,029	2.5%
6	2022	1,528,528	-2.1%	1,224,440	-5.1%
7	2023	1,402,820	-8.2%	1,197,888	-2.2%
8	CAGR[2]		-0.3%		-0.5%

Sources and Notes:
[1] DTE's response to data request ABDE-1.6.
[2] Compound annual growth rate.

Including 2023 in the calculation of the compound annual growth rate shows that O&M expenses have actually *declined* slightly year-over-year. (*Id.*; Exhibit AB-1.) Importantly, both sets of data (actual and adjusted) show that despite inflationary pressures in 2022 DTE's actual O&M expense decreased by 2.1% relative to 2021, and its adjusted O&M expense decreased by 5.1%. While DTE noted that 2023 was a financially challenging year, the Company still successfully managed its costs such that O&M decreased in 2023 relative to 2022. (*Id.*) Despite its elevated inflation projections, therefore, the Company is clearly capable of managing its O&M expenses such that they do not change at the same rate as inflation. (*Id.*)

The Company is explicitly proactive in this regard. Specifically, DTE has indicated that it strives to identify and execute sustainable productivity improvements and leverage new technology to help control the Company's cost structure over the long term, and that it has been able to offset inflation in prior years. (See Exhibit AB-1 at 3-6.) The Company noted that it is using its process improvement methodologies to hold costs below the inflation rate, which is supported by the data above demonstrating the Company's ability to manage its O&M expenses such that they do not change at the same rate as inflation. (*Id*.) Further, DTE expects reductions in O&M expenses as a result of proposed distribution system capital investments over the next five to ten years, and the transition of the generation fleet from coal to other alternatives. (*Id*.) In other words, there is every reason to believe DTE's O&M expenses will not increase above the rate of inflation.

The Company's proposed inflation adjustment is also flawed as it was estimated by the Company using a composite inflation rate based on a blend of the CPI-Urban ("CPI-U") published by S&P/IHS Markit and a projected wage inflation rate of 3.0% for both internal labor and contract labor. (York 6 Tr 3340-42.) The Company used the 3.0% wage escalator for labor costs and the CPI for non-labor cost. (*Id*. (internal citations omitted).) Despite the Company's claim to the contrary, this "blended" approach has in fact been rejected multiple times. (See Foley 2 Tr 174; Case No. U-21291, Proposal for Decision at 266 (citing to the Commission's rejection of this approach in Case Nos. U-20561 and U-20940).) These CPI-U inflation rates are also outdated as they were projected in October 2023; more recent data from the Blue Chip Economic Indicators industry expert consensus Real GDP Chained Price Index shows rates of 2.3% for 2024, and 1.8% for 2025. (York 6 Tr 3340-42.) It is more important to use projections of future escalators from independent economists, as these independent economists have no interest in the outcome of this rate case. (*Id*.)

Further, the Company's wage escalation assumption does not consider that certain escalations may be managed such that the expense may not increase at the overall cost of inflation. (*Id*.) For instance, the Company's labor expense involves many moving pieces, including changes in the number of new employees, which would potentially be brought on at lower wages than the average wage of existing employees, and recognizing that certain employees may retire over time and be replaced by new, less experienced employees at lower wages. (*Id*.) The Company's projected wage escalation does not account for any of these realities or consider how they may impact its test year O&M costs.

Given the flaws in the Company's proposal the Commission should instead approve projected inflation rates based on the Real GDP Chained Price Index for test year labor and non-labor O&M expense, as set forth above (i.e., 2.3% for 2024 and 1.8% for 2025). The Real GDP index uses a "chained" methodology, meaning each year the basket of goods and services is updated to reflect what people are actually buying. (*Id*.) This is unlike the CPI, which uses a fixed basket for a set period. The Real GDP index is therefore more responsive to consumer substitution (i.e., if prices of certain goods rise, people might switch to less expensive alternatives, and the index will reflect that change). (*Id*.) Thus, while the Company claimed that the "basket of goods incorporated in the CPI is updated periodically" to "reflect more recent consumer spending pattern," the Real GDP Chained Price Index offers a more nuanced and relevant perspective for projecting electricity costs. (Foley 2 Tr 175-76; York 6 Tr 3340-42.) Specifically, it reflects a more comprehensive approach to measuring price changes in the broader economy and includes a focus on sector-specific impacts including considerations of the prices of inputs that utilities rely on like fuel, materials and labor. (*Id*.) This makes it a superior choice for capturing the economic dynamics that influence utility expenses.

For instance, the CPI can be heavily weighted by the cost of medical expenses, which is not reflective of utility expenses, and DTE generally failed to account for projected changes in the tenure of employees, or the impact of productivity enhancements that will likely reduce escalation of actual costs to levels below the rate of inflation, but it does rely on independent factors to project escalations in labor costs. (York 6 Tr 3340-42.) Adopting these inflation factors will reduce DTE's projected O&M expense by $45.2 million.

2. The Company's proposed incentive compensation recovery is unreasonable and should be rejected.[24]

The Company proposed recovering $59.504 million of incentive compensation expense in this case, including $39.232 million associated with DTE's financial performance and $9.539 million associated with certain operational performance measures which the Company did not satisfy. (Fix 6 Tr 2875.) As this amount should not be recovered from ratepayers, consistent with past Commission precedent, the Commission should reject cost recovery.

Incentive compensation programs designed to align the interests of employees with shareholders should be paid for by shareholders. (See York 6 Tr 3343-47.) To the extent incentive compensation reflects customer-directed goals such as service reliability, and/or employee safety, only then is it fair and reasonable to consider recovering program costs from ratepayers if the operational performance metrics are actually achieved. (*Id.*)

[24] This issue is addressed at Foley 2 Tr 185-86 (recommending the Commission approve DTE's proposed incentive compensation); Uzenski 6 Tr 1489-91, 1546-47, 1570-74 (explaining DTE's proposed incentive compensation); Fix 6 Tr 2868-97, 2904-07 (recommending the Commission approve DTE's proposed incentive compensation); York 6 Tr 3343-47 (objecting to recovery of certain incentive compensation amounts); Coppola 3642-48, 3699-707 (objecting to recovery of certain incentive compensation amounts); Stults 6 Tr 4263-65 (objecting to recovery of certain incentive compensation amounts); McMillan-Sepkoski 6 Tr 4922-25 (objecting to recovery of certain incentive compensation amounts).

The Commission has consistently agreed with this approach. See *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered December 22, 2021 (Case No. U-20963), pp 297-98 ("The contention that ratepayers receive benefits from a financially healthy utility is insufficient to demonstrate that incentive compensation tied to financial performance does not primarily benefit shareholders or that benefits to ratepayers are commensurate with the proposed expense for the incentive compensation program").[25] Specifically, the Commission has stated that it has "unequivocally and consistently disallowed incentive compensation costs tied to financial measures." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-20561), pp 17-19. Thus, "financial-based incentive compensation costs—regardless of when and how they were incurred, the accounting treatment utilized, or whether they were classified as capital expenses or O&M—should not be included in the rates approved." *Id*.

Here, DTE acknowledged that the Commission has indicated in all its recent Orders addressing incentive compensation programs that inclusion of incentive compensation expense in a revenue requirement is dependent on showing that the incentive compensation programs provided benefits to customers in excess of the expense. (Fix 6 Tr 2891.) Despite this acknowledgement the Company here did not demonstrate that customers benefit from incentive compensation tied to financial performance metrics. Specifically, as shown on DTE's Exhibit A-21, Schedule K-6, the costs associated with financial performance outweigh the benefits to customers in six out of seven metrics and cost $39.232 million while only providing $19.946

[25] The Company's assertion that ABATE's position ignores "unquantifiable benefits" that cannot be measured is therefore directly contrary to the Commission's finding in Case No. U-20963 and does not provide a reasonable basis for establishing costs customers must pay through their rates. (See Fix 6 Tr 2905-06.)

million in customer benefits. As such the Commission should reject recovery of this $39.232 million in incentive compensation associated with DTE's financial performance.

The Company's incentive compensation request also included cost recovery associated with certain operational performance measures for which the benefits also do not exceed the expense. (See York 6 Tr 3345-47.) For instance, the expense associated with Customer Satisfaction measures is $5.848 million while the benefit is only $2.264 million. (*Id*.; Exhibit A-21, Schedule K-6.) Similarly, the benefits do not outweigh the expenses related to certain Safety & Engagement measures (e.g., OSHA Recordable Incident Rate, DTE Energy High Energy Serious Injury or Fatality, Nuclear Total Industrial Safety Accident Events, and Nuclear On-Line Radiation Exposure). (*Id*.) Taken together these program expenses exceed their purported benefits by $5.644 million. (*Id*.) Similarly, the Company's projected incentive compensation levels include $1.937 million for meeting target values for SAIDI excluding MEDs, and $1.958 million for CEMI4. (*Id*.) The Company did not achieve the target values for these metrics in 2023 and it is not reasonably certain the Company will do so during the future test year. (*Id*.) For instance, while the target SAIDI excluding MEDs in 2023 was 150 minutes, DTE achieved 157 minutes. (*Id*.; Fix 6 Tr 2907.) Similarly, while the target CEMI4 percentage was 7.55% the Company achieved 13.38%. (*Id*.) The Company's assertion that it should be compensated for paying out incentive compensation related to target performance levels even if it does not meet those levels is entirely unreasonable. (Fix 6 Tr 2907.) There is no reason customers should be paying the Company performance incentives for providing service that does not meet target performance levels. In light of the Company's recent failure to meet its reliability goals, as well as its track record of historic revenue sufficiency amounts, the incentive compensation associated with achieving these distribution reliability metrics should also not be recovered from ratepayers. Specifically, at a minimum, the

Company's projected test year incentive compensation expense tied to operational performance measures should be reduced by a total of $9.539 million (i.e., the sum of $5.644 million, $1.937 million, and $1.958 million).

The Company has not demonstrated that certain requested incentive compensation cost recovery sufficiently benefits ratepayers. As such the Commission should disallow cost recovery of at least $48.8 million related to incentive compensation.

E. Cost of Service, Rate Design, and Tariffs – The MNSC distribution rate design and Staff purchased capacity cost allocation proposals should be rejected.

1. The MNSC distribution rate design proposal is based on flawed reasoning.[26]

MNSC requested that the Commission direct DTE to, in its next rate case, submit a seasonal approach to distribution rates reflecting that the relative utilization of the distribution system is seasonal. (Jester 6 Tr 3795-800.) While MNSC has only requested the Company file certain information in its next rate case, the Commission should take note that this approach to allocating distribution rates is flawed.

MNSC argued that the proper basis of both cost of service and rate design of distribution costs is the degree of capacity utilization, not nominal loading, and thus the rates should be seasonal. (*Id.*) This perspective is incorrect and should not be countenanced. In general, utilization

[26] This issue is addressed at Maroun 6 Tr 2791-95 (objecting to MNSC's proposal); Dauphinais 6 Tr 3415-16 (objecting to MNSC's proposal); Jester 6 Tr 3795-800 (recommending DTE submit a seasonal approach to distribution rates reflecting that the relative utilization of the distribution system is seasonal). The portion of Mr. Dauphinais' Rebuttal Testimony addressing MNSC's production cost allocation proposal (Dauphinais 6 Tr 3395-415) refers to MNSC testimony which was not ultimately entered into the record and thus that portion of Mr. Dauphinais' Rebuttal Testimony (Dauphinais 6 Tr 3395-415) should be disregarded for the purposes of this proceeding. Further, Mr. Dauphinais' proposal regarding modifications to Rider 10 (Dauphinais 6 Tr 3383-84; Burgdorf 6 Tr 2351-52) is not being recommended in this proceeding and is therefore no longer a contested issue.

does not align with cost causation unless either the cost in question involves incurring a variable cost based on utilization, or the utilization period is limited to demand in the specific hours that cause the utility to incur infrastructure costs. (Dauphinais 6 Tr 3415-16.) Thus, just because a distribution transformer's loss of life may be higher in certain seasons than others does not mean the allocation of all distribution costs should be based on seasonal utilization, even if distribution equipment ratings are sensitive to ambient temperature. (*Id*.)

Given this flaw in the basis for MNSC's assertion and request, ABATE does not support DTE adopting either a distribution class cost of service method or a distribution rate design that is based on seasonal utilization. While ABATE does not object to the Company filing additional information in its next rate case the Commission should note the flaws in this proposal.

2. Staff's purchased capacity cost allocation proposal is flawed and should be rejected.[27]

Staff disagreed with DTE's position that purchased capacity costs should be allocated based on the 4CP (coincident peak), 100% demand (but excluding the R10 rate class), and instead proposed that purchased capacity costs be allocated using the 4CP 75-0-25 allocator. (Pung 6 Tr 4950-51.) As DTE's purchased capacity costs are largely related to renewable energy assets with costs that are largely fixed the Commission should reject this proposal.

Staff's proposal is inconsistent with the fact that the vast majority (95%) of these costs are related to renewable facilities required under Public Act 295 of 2008. (Andrews 6 Tr 3508-13.) Specifically, the Company's owned renewable assets comprise 69% of the total while its PURPA contracts and other renewable Purchased Power Agreements ("PPA") make up the rest, along with

[27] This issued is addressed at Maroun 6 Tr 2796-97 (recommending the Commission reject Staff's proposal); Andrews 6 Tr 3508-13 (recommending the Commission reject Staff's proposal); Pung 6 Tr 4950-51 (recommending the Commission allocate purchased capacity costs using the 4CP 75-0-25 allocator).

a small offset for DTE's capacity sales. (*Id*.) These figures represent what DTE has determined to be the capacity related portion of these assets. (See *Id*.) In total, the PA 295 assets have a cost of $388.3 million, which cost DTE has separated into those which are "fuel related" (which is simply the portion of the asset cost that has not been deemed to be capacity-related based on the fixed-cost proportion of the transfer prices) and "capacity-related." (*Id*.; see also Exhibit AB-26, Schedule P2.) From this delineation $130.4 million of these costs is capacity-related and $257.9 million is "fuel-related." (*Id*.)

The Company's proposed approach would allocate $130.4 million deemed capacity-related using Allocator 251, which is 100% 4CP demand, excluding the R10 class. (*Id*.) The $257.9 million of "fuel-related" PA 295 asset costs is allocated using allocator 111, which is 100% energy, excluding the R10 class. (*Id*.) Therefore, 66% of these costs are allocated on the basis of energy and 34% are allocated on the basis of 4CP demands under DTE's proposal. (*Id*.) Under Staff's proposal to allocate the capacity-related portion with the 4CP 75-0-25, however, the amount allocated on energy would increase to approximately 75%, and demand would decrease to 25%. (*Id*.)

This proposal is inconsistent with the fact that 89% of DTE's costs for its owned renewable facilities are entirely fixed, meaning they have no material fuel costs. (*Id*.) Indeed, renewable facilities like wind and solar assets have no fuel costs; the majority of the asset costs are incurred when they are installed with little variable production expense. (*Id*.) In other words, regardless of customer energy consumption, or even energy generation, 89% of these costs would remain fixed and should be allocated as such. (*Id*.) Allocating the capacity-related portion of the PA 295 renewable assets using the 4CP 75-0-25 allocator instead is therefore unreasonable and inconsistent with the nature of these assets and their costs. Again, the Company's PA 295

renewable resources are largely fixed cost assets, and 66% of the costs of these assets are already allocated on the basis of energy. While the 4CP 75-0-25 allocator might be appropriate for these costs if they were allocated in the same manner, as with DTE's traditional production resources, that is simply not the case with the PA 295 renewable resource costs.

Thus, if Staff's proposal were adopted 75% of the PA 295 renewable resource costs would be allocated on the basis of energy despite as much as 89% of these costs being fixed. (*Id*.) No additional energy allocation should therefore be approved, and the current methodology should remain in effect. Indeed, as the current methodology already over-allocates on the basis of energy because the majority of the purchased capacity costs are related to DTE's owned renewable generation facilities Staff's proposal would only exacerbate this incongruity. (*Id*.) If the Commission is to make any modification to the allocation of DTE's PA 295 renewable assets, it should therefore allocate them more on the basis of demand in contravention of Staff's proposal.

Staff's proposal is unreasonable and inconsistent with the actual nature of these costs and would shift $4.1 million to the Primary classes and $0.2 million to each of the Secondary and Lighting classes. (*Id*.) This is plainly unreasonable. As such, the Commission should reject Staff' proposal and DTE's purchased capacity costs should continue to be allocated using the 100% 4CP allocator, specifically, DTE's allocator 251.

F. Other Issues – Numerous IRM proposals are unreasonable and should be rejected.[28]

The Company made a number of proposals related to its IRM, including the following: (i) adding up to $434.1 million of investment to Year 2 of the authorized distribution IRM; (ii) adding

[28] This issue is addressed at Foley 2 Tr 114-28, 151-275, Hartwick 4 Tr 633-45, Elliot Andahazy 4 Tr 909-11, Deol 5 Tr 1135-36, Uzenski 6 Tr 1556-57, Willis 6 Tr 2613, Maroun 6 Tr 2775-76, and Vanglider 6 Tr 2818-22 (recommending the Company's IRM proposals); Dauphinais 6 Tr 3380-82 (recommending the Commission reject certain of the Company's IRM proposals); Alvarez 6 Tr 3924-47 (recommending the Commission reject certain of the Company's IRM

a new category of investment called "Pole and Pole Tape Maintenance and Modernization"; (iii) expanding the scope of "4.8 kV Circuit Automation" to "Distribution Automation"; and (iv) adding a Year 4 to the distribution IRM. (Foley 2 Tr 114-19.) As none of these proposals are reasonable the Commission should reject the same.

The Company's IRM was only recently approved in its last electric rate case (Case No. U-21297) where the Commission found that "limiting the approval to the first two years will allow the company to move forward with the IRM without precluding the incorporation of any potential insights gained from those proceedings to better inform the potential continuation of the IRM." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered December 1, 2023 (Case No. U-21297), pp 289-91. It has not even been one year since that approval, hedged by the Commission's prudence in awaiting further insights from additional proceedings to better inform the potential continuation of the IRM, and yet DTE has requested approval to dramatically expand this mechanism. The distribution IRM is still very much in its infancy; Year 1 had only barely commenced seven months prior to the Company filing its direct testimony and the first DTE distribution IRM reconciliation will not commence until sometime in 2025. (Dauphinais 6 Tr 3380-82.) As such the Company's distribution IRM term should continue to be limited to no longer than truly necessary, as the Commission just concluded in December, until potential insights from Case Nos. U-21400 and U-21305 can inform potential continuation of the mechanism. (*Id*.)

proposals); Stephens 6 Tr 3999-4030 (recommending the Commission reject certain of the Company's IRM proposals); Perry 6 Tr 4725-34, 1736-40 (recommending the Commission take certain measures if it approves the Company's proposal); Evans 6 Tr 5232-37 (objecting to the Company's proposals other than modifying the scope of "4.8 kV Circuit Automation" to "Distribution Automation" after the conclusion of IRM Plan Year 2).

Having said that, to address DTE's concern with respect to a temporary stopping and starting of its distribution IRM, and to potentially reduce the likelihood DTE will file a rate case in 2025 for the sole purpose of adding a Year 3 to its distribution IRM, it may not be unreasonable for the Commission to permit a Year 3 for the Company's distribution IRM for the existing investment categories of "Conversions," "Subtransmission Redesign and Rebuild," "Breaker Replacement" and "URD Replacement" in the amounts proposed by DTE in this proceeding for Year 3, which total to $275.0 million. (*Id*.) This would time only authorize one additional year for the distribution IRM and only do so for a level of investment similar to that already authorized for Year 2 ($290.1 million). (*Id*.) Regarding a Year 4, however, the risk of a temporary lapse in the distribution IRM is sufficiently addressed by adding a Year 3 in the limited manner described above. Approving a Year 4 at this time would essentially presume a long-term future that has not yet been determined to be reasonable or prudent.

Thus, while a Year 3 for the distribution IRM may not be unreasonable as set forth above, the remainder of the Company's proposals are not reasonable or prudent. As such the Commission should reject the same.

G. Other Issues – The Commission should reject MEIU's proposal for the TEP to account for societal benefits.[29]

MEIU requested that the Commission require DTE to account for social benefits, including greenhouse gas and criteria pollutant emissions reductions, in its BCA for its TEP. (Sherman 6 Tr 4070-80.) While the use of the Societal Cost Test ("SCT") for informational purposes as a

[29] This issue is addressed at Dauphinais 6 Tr 3416-17 (arguing that societal benefits cannot be factored into a BCA); Sherman 6 Tr 4070-80 (recommending societal benefits be incorporating into DTE's TEP BCA); Revere 6 Tr 4977-78 (explaining that a societal cost test "is not appropriate to use to determine the amount to which such programs should be funded by utility customers regardless of the societal benefits they may produce").

sensitivity case is not necessarily objectionable, the Commission should not order the use of the SCT, or the inclusion of societal benefits (e.g., greenhouse gas and criteria pollutant emissions) in DTE's base case BCA for its TEP. (Dauphinais 6 Tr 3417.)

Despite MEIU raising similar arguments regarding this issue in DTE's last rate case, the PFD properly rejected "the general ideas offered by MNSC and MEIU to broadly consider the benefits (whether financial or otherwise) of all EVs within DTE's service territory." (Case No. U-21297, PFD at 690.) The PFD found that "[t]o do so would ascribe benefits to EV programs that would have occurred even absent the EV programs" and to "the extent that EVs have environmental or health benefits, such benefits would have to be quantified and linked to DTE's programs to be factored into the BCA." (*Id*.) The Commission endorsed this analysis, stating the "ALJ also noted that quantifying costs and benefits is extremely difficult and discussed the merits and deficiencies of each party's presentation" before recommending "that, for future BCAs, the parties collaborate to prepare a more comprehensive BCA and that the topic should be included in Transportation Electrification Plan (TEP) stakeholder discussions." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered December 1, 2023 (Case No. U-21297), pp 691-92. The Commission found "the ALJ's analysis and recommendations in this matter to be comprehensive, thorough, and well-reasoned" and adopted the recommendation. *Id*. Further, the Commission clarified its belief "that encouraging a forum by which the company and utilities can continue to engage in ongoing conversations around the costs and benefits of the company's EV charging programs is supportive of this continued evolution" of the EV market. *Id*. This finding was also "consistent with the ALJ's recommendation that 'the parties collaborate to prepare a more comprehensive BCA and that the topic should be included in [TEP] stakeholder discussions.'" *Id*. Thus, the Commission "emphasize[ed] that development of

the TEP with meaningful discussion of related concerns is best conducted through stakeholder meetings rather than in a rate case proceeding." *Id*. The proper place for evaluating the SCT and societal benefits related to the TEP is therefore in stakeholder meetings, rather than this contested case.

This point is further evidenced by Staff's August 12, 2024 Reply Comments in Case No. U-21429, where Staff explained the following:

> Recent events at the Commission have demonstrated that there is a broad perspective on BCAs and what components are appropriate for a BCA. Staff maintains that the Utility Cost Test is the most appropriate test for the Commission to consider although other tests can be informative to helping make certain decisions. Utility costs, as compared to other costs in other tests, are well known to the parties in MPSC filings and are under the control of the utility. These costs are also under the authority of the commission regarding rate recovery.
>
> Specifically, regarding the Societal Cost Test (SCT), it is clear that carbon reductions in the utility industry are the responsibility of the utility and hence utility customers. It is much less clear to what extent carbon reductions in the transportation industry are the responsibility of the utility and hence utility customers. It also appears clear that while carbon reduction in the transportation industry is the responsibility of society, it is also true that the MPSC and utilities are only a part of society and the burden for these programs should not rest entirely on the Commission nor the utilities. Also, as discussed above, many participants in Commission cases are not in a place to comment on the appropriateness of certain societal costs nor are all the parties in agreement as to the appropriateness for consideration. As an example, money from the National Electric Vehicle Infrastructure (NEVI) program is clearly external to utility costs in the Utility Cost Test (UCT), but it is money that will inevitably be paid for by society through taxes. In Staff's opinion, not held by all parties, the NEVI funds should be included as a societal cost in the SCT.[30]

The Commission should therefore reject MEUI's request to require that DTE account for social benefits, including greenhouse gas and criteria pollutant emissions reductions, in its BCA

[30] See also Armstrong 6 Tr 5216 (addressing another issue but explaining that "[m]any non-energy benefits lack standardized measurement methodologies" such as "assigning a monetary value to improved health outcomes [] can be highly subjective and vary significantly depending on the methodology used" and "this complexity and the inherent uncertainty can lead to variable and subjective estimates that may not be reliable").

for its TEP. In addition, the Commission should not direct DTE to pursue or expand its TEP on the basis of societal benefits associated with avoided transportation emissions. Doing so would effectively amount to mandating electric ratepayers subsidize the cost of providing the claimed societal benefits. To the extent the Commission grants the request of MEIU witness Sherman, it should be limited to the provision of a sensitivity case for the BCA for the DTE TEP.

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

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Date: October 3, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

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

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF WAYNE)

Stephen A. Campbell, being first duly sworn, deposes and says that on October 3, 2024, he did cause to be served the ***Association of Businesses Advocating Tariff Equity's Initial Brief,*** and this ***Proof of Service***, in the above docket, via electronic mail, to the persons identified on the attached service list.

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