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July 16, 2024

VIA ELECTRONIC CASE FILING

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

Re: Case No. U-21291 – In the matter of the application of DTE Gas Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, 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 proceeding.

Sincerely,

CLARK HILL PLC

Stephen A. Campbell

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SAC/lkd
cc: Parties of Record

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **DTE GAS COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority	)	Case No. U-21291 ALJ Jonathan F. Thoits

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 Gas Company ("DTE" or the "Company") before the Michigan Public Service Commission ("Commission") in accordance with the schedule established by the presiding Administrative Law Judge ("ALJ").

TABLE OF CONTENTS

I. INTRODUCTION

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 costs which are conjectural and 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 projected operations and maintenance ("O&M") costs are inflated and its requested return on equity ("ROE") and equity ratio are excessive, inadequately supported, and unnecessary. The Company's recommended class cost-of-service study ("CCOSS") and rate design are also unreasonable and would not best align costs with their causation.

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 by those customers.

II. ARGUMENT

A. The Commission should consider DTE's requested rate increase in the context of its historic costs and revenue sufficiency.[1]

The Company based its requested revenue increase on projected expenses. (See DTE Application at 2.) Because the use of projected test years has resulted in excessive recovery the Commission should instead approve a revenue requirement based on the Company's historic test year.

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 the evidence. MCL 460.26(8); *Attorney General v Mich Pub Serv Comm*, 249 Mich App 424, 429 (2002). Specifically, the Legislature's treatment of using 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*, ___ Mich App ___ (Docket No. 351261, July 29, 2021);[2] 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[3] (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

[1] This issue is addressed at York 4 Tr 1262-70 (objecting to the use of a projected test year); Telang 4 Tr 1874-75 (recommending projected test year).

[2] Also available at Case No. U-20322 Filing No. U-20322-0266 (July 29, 2021).

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

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 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. Stated differently, projected test years allow DTE to begin recovering costs before they have been verified as being real and prudently incurred. (York 4 Tr 1262-70.) Using these projections to set rate increases 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*.)

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.[4]

This case further highlights the inequity of basing DTE's requested rate increase on cost projections given the Company's historic revenue surpluses. In this proceeding the Company reported a large revenue *sufficiency* of approximately $35.7 million in its historic test year, while in four of its last five rate cases the Company also reported a historic test year revenue sufficiency. (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.[5] The Company has also not provided

[4] The speculative nature of these potential costs is inherent in their projected nature. The Company's claim that "use of a projected test year does not mean that the projected costs are not real or prudent" is entirely inconsistent with the fact that these costs have not been, and may not be, incurred. (Telang 4 Tr 1874-76.) While known and measurable changes are changes to costs that are inescapable and precisely identifiable in amount and timing, future projected expenses are often not inescapable, not precisely identifiable in amount and timing, or both. (See York 4 Tr 1262-70.) As demonstrated further below and throughout the record, 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.

[5] "[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).

any evidence that it experienced a revenue deficiency in 2023, although the time that has passed since its last rate case filing suggests it realized an additional revenue sufficiency in that year. (*Id*.)

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. Instead the Commission should grant DTE a revenue increase no greater than the Company's proposal to roll $106.5 million of revenue requirement associated with its IRM surcharge into base rates.

If, despite this recommendation, the Commission elects to approve the use of a projected test year it should 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.

In addition, the Commission should continue to be much more vigilant in ensuring DTE's projected expenses and investments are truly necessary to provide reliable service at lowest reasonable cost, and ensure that DTE is irrevocably committed to incur its projected expenses and investments (or otherwise cannot avoid them). Unless and until this issue is brought under control DTE will continue to earn a rate of return higher than authorized by the Commission to the ongoing detriment of customers.

B. Cost recovery for numerous proposed capital expenditures was not adequately supported and should be rejected.[6]

1. The Company's proposed investment in its Main Replacement Program is unnecessary at this time.

The Company proposed adding approximately $2.5 billion in capital investments over the rate case period, including a large IRM investment related to DTE's Main Replacement Program. (See Exhibit A-2, Schedule B5.1.) As the proposed level of capital investment in this program is unnecessary at this time the Commission should reject cost recovery for the same.

The Company requested capital expenditures for the Main Replacement Program of $265 million in the historical test year, $468 million in the projected bridge period, and $68 million in the projected test year period (a total of $801 million). (See Exhibit A-2, Schedule B5.3.) This proposal follows the Company's significant investment in this program in 2022, although in prior years the Company has demonstrated its ability to significantly reduce gas leaks without this level of investment. Specifically, according to the data reported in the U.S. Department of

[6] This issue is addressed at Fitzhenry 4 Tr 1314-21; Coppola 4 Tr 1449-50, 1452-61; Fedele 4 Tr 1979-90.

Transportation's ("DOT") Pipeline and Hazardous Materials Safety Administration's ("PHMSA") annual reports for 2018 and 2022, DTE reported 3,385 gas leaks in 2018 and only 1,693 in 2022, an approximately 50% reduction. (Fitzhenry 4 Tr 1317-18 (internal citations omitted).) Thus, DTE was able to dramatically reduce gas leaks before increasing its investment in distribution main investment by 84% (to $263 million) in 2022. (*Id*.)

This demonstrates the Company's proposed $801 million investment here is unnecessary to produce the results the Company has already achieved and seeks to maintain. Indeed, the Company's claim that "[w]hile the program has pulled ahead of the original projections, to slow the pace just to hold the 2035 completion would jeopardize that goal" is incoherent. (Janness 4 Tr 647-48.) Holding the pace to the 2035 completion date would assure that goal without resulting in unnecessarily increased costs. The Company's legacy gas mains replacement efforts have significantly reduced the average number of gas leaks per mile. Thus, DTE has demonstrated it can make system improvements through its Main Replacement Program without such a dramatically elevated level of investment. The Company only needs to retire an average of 190 miles of main each year to meet the 18-year pace approved in Case No. U-18999, which is less than the 206 miles being proposed by the Company. (4 Tr 1317-18 (internal citation omitted).) The Company can still remain on pace with the approved target miles in Case No. U-18999 by replacing 16 less miles of main per year, which would reduce the Main Replacement Program capital expenditures by approximately 8% per year. (*Id*.) This would provide a satisfactory result while reducing the cost burden the Company would otherwise impose on customers. The Commission should therefore adopt this reduction in DTE's proposal, which would result in reducing the Main Replacement Program capital expenditures by approximately $62 million.

2. The Company should not recover costs for large capital projects which will not be completed, used, or useful within the test year.

The Company proposed cost recovery for large capital projects which, for the most part, have large capital expenditures that are not considered routine in nature, are not part of IRM programs, and many of which have long project schedules extending multiple years which will not be completed prior to the end of the projected test year. (Fedele 4 Tr 1904.) As cost recovery for these projects is unreasonable here the Commission should reject the same.

Several of the projects DTE proposed are not expected to be in service until after September 30, 2025, the end of the projected test year. (Fitzhenry 4 Tr 1319-22.) Any unforeseen delays due to permitting, labor shortages, material delays, or unforeseen site conditions would therefore make it unlikely that the requested capital investment will be realized prior to the end of the projected test year. (*Id*.) The likelihood of these circumstance is demonstrated by DTE's history with large capital project delays. For instance, Phase 3 of the Company's Traverse City Alpena Reinforcement Project was completed in 2022 rather than 2021 as was proposed in the project Schedule in MPSC Case No. U-20940. (See *Id*.) This resulted in an actual spend of $40,667,000 in 2022 as opposed to the proposed spend of $640,000, a variance of approximately $40 million. (*Id*. (internal citation omitted).) The Company's claim that additional project cost recovery should not be disallowed here because this prior delay was a "prudent decision" to "allow[] the completion of Phase 3 to more closely align with DTM's in-service date" misses the point. (Fedele 4 Tr 1989.) Instead, this type of unforeseen delay is precisely the concern with these additional projects with completion dates near the end of the period relevant to this case. Additional unforeseen "prudent" delays are hardly speculative and the related projected costs which may not be incurred should not be recovered.

Indeed, delays impact rate case capital expenditures in two ways. First, projects included in prior rate cases could have additional capital expenditures spill over into the current rate case if the project experiences delays and the work approved in prior rate cases is not timely completed. (*Id*.) Second, a similar issue can occur in the projected test year of the current rate case; if the large capital projects in this proceeding experience project delays the proposed level of capital investment will not be realized by the end of the projected test year. (*Id*.) The combination of these two issues can create a squeezing effect on the rate case historical and future test year periods, where both historical and future capital expenditures are included in customer rates despite the fact that not all of the proposed capital investments have been placed into service. As such, it is unreasonable to approve cost recovery for the projects which have a very real risk of not being completed within the test year period

The Commission should therefore not approve cost recovery for projects with completion schedules at the end of the test year. In other words, the Commission should reduce the proposed capital expenditures in the future test year period to ensure customers will not pay for work that is not completed. (*Id*.) A reasonable approach would be to remove the last six months of the Company's proposed capital investment for the projects described below:

Table CTF-4

Capital Projects with Expenditures Impacted by Project Delays
($1,000s)

Project Description	In-Service Date[1]	Projected Test Year Company Proposed[2]	Adjustment	Adjusted CapEx
Fort Street Main Replacement	12/31/2027	$32,753	($16,799)	$15,954
Austin-Detroit A/B Lines	12/31/2028	$16,181	($9,778)	$6,404
Belle River - Detroit Interconnect and Loop Project	1/31/2027	$7,378	($4,750)	$2,628
E-line Interconnect (CMS Line 2700)	11/30/2025	$4,694	($2,937)	$1,758
ILI Expansion - Muskegon - Ludington (10) - Scottville Tie In	10/31/2025	$4,101	($2,051)	$2,051
Taggart Compressor Replacement	12/31/2027	$2,859	($2,000)	$859
ILI Expansion – Belle River Field Headers (24" Traps)	10/30/2025	$3,263	($1,632)	$1,632
Total	Total	$71,230	($39,945)	$31,285

Sources:
[1] Attachment: U-21291 ABDG-1.30 - Top 25 Gantt Chart provided in Response to Data Request ABDG-1.30.
[2] Exhibit A-12, Schedule B5.3.

This adjustment would remove approximately $40 million of proposed capital expenditures from the projected test year. Such an approach will ensure that customers will not be subject to cost recovery for project work that is not completed during the projected rate case period.

C. The Company's proposed O&M expense is unreasonable and should be rejected.

The Company requested O&M cost recovery of approximately $538 million, a net increase of $11 million over the historical test period. (See Exhibit A-12, Schedule B6.1.) As this proposal is unreasonable and inflated the Commission should reject the Company's request.

1. The inflation factor used in the Company's analysis is unreasonable.[7]

The Company proposed an upward adjustment of $30.5 million in O&M expense related to inflation, using labor inflation rates of 3.2% for 2023, 2.9% for 2024, and 2.9% for 2025. (See Exhibit A-13, Schedule C12.) These labor inflation rates are based on a weighted average of the labor inflation, contractor inflation, and non-labor inflation rates each year. (*Id.*; see Fitzhenry 4

[7] This issue is addressed at Fitzhenry 4 Tr 1322-25; Coppola 4 Tr 1529-34; Telang 4 Tr 1872-73; Cooper 4 Tr 2689-91.

Tr 1322-25.) Both the labor and contractor inflation rates are based on the same wage inflation rate of 3.0% and are used for all O&M expense categories regardless of the function. (*Id*.) This figure was not adequately supported and should be rejected.

The Company did not produce any supporting workpapers to support the 3.0% assumption for the expected labor cost escalation assumption. (*Id*.) Instead, the Company supported the wage inflation factor by relying on historical practices for the non-represented workforce and existing collective bargaining agreements for represented employees. (Cooper 4 Tr 2689.) This observation lacks objectivity and does not provide a transparent justification supporting the Company's figures. Further, while the Company supplemented this argument with historical annual pay increases over the period 2019-2023, this analysis included executive pay and incentive compensation, which is not reflective of the average salary of the Company's larger workforce. (Cooper 4 Tr 2690; Exhibit AB-20 at 4.) In addition, the historical annual employee pay analysis did not take into account changes in the number of employees throughout the calendar year. If instead the Company looked at the year-over-year change in average salary, the Company's own workpapers would have shown an average pay increase of 1.1% in 2020, 2.7% in 2021, 1.8% in 2022, and 0.6% in 2023, for an average increase of 1.5%. (See Exhibit AB-20 at 1-3.)

The lack of evidentiary support demonstrates the unreasonableness of this figure. If the Company is experiencing increased labor cost it should have supported the 3.0% wage inflation rate with workpapers or some other evidence. The absence of that evidence demonstrates the 3.0% wage inflation rate should not be relied on to escalate O&M expense.

Further, in terms of the non-labor inflation rate used by DTE, the Company used the CPI-U (Consumer Price Index for Urban Customers) to determine the appropriate non-labor inflation rate, which resulted in proposed non-labor inflation rates of 4.1% for 2023, 2.9% for 2024, and

2.2% for 2025. (*Id*.) Comparing these proposed rates to the Blue Chip Economic Indicators industry expert consensus GDP Chained Price Index over the same time period (2.6% for 2023, 2.2% for 2024, and 2.2% for 2025) demonstrates they are inflated for each year until 2025. (*Id*.) The GDP chained price index uses a "chained" methodology and each year, the basket of goods and services is updated to reflect what people are actually buying. (See Fitzhenry 4 Tr 1322-25.) This is unlike the CPI, which uses a fixed basket for a set period. This makes the GDP deflator more responsive to consumer substitution because the index reflects changes, such as if prices of certain goods rise and people switch to cheaper alternatives. In addition, the CPI can be heavily weighted by the cost of medical expenses, which is not reflective of the cost of utility expenses. (*Id*.) The Commission should therefore approve using the Blue Chip GDP Chained Price Index for the Company's O&M inflation factors. The wage inflation rate used by the Company instead is not well supported, and the CPI-U non-labor inflation rate is well above the consensus industry experts' opinion of the GDP Chained Price Index. (*Id*.) Adjusting the inflation factor accordingly will reduce the Company's proposed O&M expense by approximately $6.9 million.

2. The Company's proposed incentive compensation recovery is unreasonable and should be rejected.[8]

The Company proposed recovering $18.2 million of incentive compensation expense in this case. (Cooper 4 Tr 2644-56.) This represents the non-capitalized portion of incentive compensation related to operating measures associated with the Annual Incentive Plan ("AIP") and Rewarding Employees ("REP"), and the total (non-capitalized) cost associated with the Long-Term Incentive Plan ("LTIP"). (*Id*.) This expense contains $12 million of incentive

[8] This issue is addressed at Fitzhenry 4 Tr 1325-27; Coppola 4 Tr 1543-49; McMillan-Sepkoski 4 Tr 1698-1701; Cooper 4 Tr 2636-39, 2644-78.

compensation tied to DTE's financial performance which, consistent with past Commission precedent, should not be recovered.

All three of the employee incentive expense elements above contain measures impacted by financial performance with goals such as realizing the Company's operating earnings objectives, cash from operations, and operating earnings per share. (See *Id*.; Fitzhenry 4 Tr 1325-28.) Taken together the amount associated with financial performance is $12.0 million. (*IdI.*) As they do not benefit from these goals it is not reasonable or appropriate for customers to contribute to these costs. In other words, incentive compensation programs designed to align the interests of employees with shareholders should be paid for by shareholders. 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*.)

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").[9] 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*

[9] The Company's assertion that ABATE's position ignores "customer benefits related to the maintenance of the Company's current debt ratings and the related avoided increased interest costs, and the operating and capital cost savings enabled by an organizational emphasis on operating efficiencies that produce improved earnings and cashflow" is therefore directly contrary to the Commission's finding in Case No. U-20963. (See Cooper 4 Tr 2674.)

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*.) 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-19, Schedule I-5, the costs associated with financial performance outweigh the benefits to customers in five out of six metrics.

The Commission should therefore again reject DTE's proposal to recover $12.0 million of incentive compensation expense associated with financial performance. These expenditures do not benefit customers and should not be paid by ratepayers.

D. A reasonable ROE for the Company is 9.45%.[10]

A utility's cost of common equity is the expected return that investors require on an investment in the utility. (Walters 4 Tr 1335-36.) 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

[10] This issue is addressed at Bandyk 4 Tr 950-65 (recommending a 9.46% ROE); Koeppel 4 Tr 1021-22 (recommending a lower ROE); Walters 4 Tr 1336-1417 (recommending a 50% equity ratio and 9.45% ROE); Coppola 4 Tr 1480-1513 (recommending a 50% equity ratio and 9.85% ROE); Ufolla 4 Tr 1612-33 (recommending a 51% equity ratio and 9.8% ROE); Lepczyk 4 Tr 2187-2211 (recommending a 51.5% equity ratio); Villadsen 4 Tr 2446-2597 (recommending a 51.5% equity ratio and 10.25% ROE).

industry as well as the Company's specific circumstances its ROE should be set at no higher than 9.45%.

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 ROE of 10.25%. (See Villadsen 4 Tr 2541.) Because this proposal is inconsistent with utility industry trends, access to capital, and credit strength it should be rejected.

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%).[11] (Walters 4 Tr 1337-54.) 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.[12] (*Id*.) Consistent with these improvements, capital expenditures for electric and natural gas utilities have increased

[11] 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").

[12] The Company's claims that "these credit rating discussions have no bearing on the cost of equity" and the "assertion that DTE's credit rating has implications for the riskiness of its ROE is unfounded" are inaccurate. (Villadsen 4 Tr 2587.) A company with a higher credit rating will have

while utilities have been able to readily access external capital. (*Id*.) Indeed, capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over the period 2023 into 2024, and the 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 these capital expenditures 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 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

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.

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 to around a 2% level. (*Id*.) 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 unwinding that Quantitative Easing program and taking actions toward monetary policy normalization. (*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*.)

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 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." (*Id*. (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. (*Id*.) 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 9.45%.

2. The Company's risk and reasonably-applied empirical analyses demonstrate that DTE's ROE should be set at no higher than 9.45%

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 4 Tr 1357-58.) DTE's current corporate bond ratings from S&P and Moody's are A- and A3 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 its "very low-risk, regulated gas utility operations, very large customer base, and effective regulatory risk management." (*Id*. (internal citation omitted).) The Company's "operations provide indispensable services that are strategically important to economies, feature material barriers to entry, and essentially operate as a monopoly insulated from market challenges." (*Id*. (internal citation omitted).) The Company also "benefits from the strength of the regulatory support in Michigan by managing its costs, filing forward-looking rate cases, and using various riders that enhance its cash flow predictability." (*Id*.) In addition, DTE "operates under a revenue decoupling mechanism that supports cash flow stability" and has a "large, diverse base of 1.3 million customers and constructive regulation; the predominance of residential and commercial customers limits its susceptibility to economic cyclicality, further supporting our expectation for stable cash flows." (*Id*. (internal citation omitted).) Thus, S&P assessed DTE "in

the upper-half of its business risk profile category compared to peers." (*Id*. (internal citation omitted).) In terms of financial risk S&P described DTE's "low-risk, regulated utility business model and effective management of regulatory risk compared with its peers" in addition to its "timely recovery of its capital expenditure and costs." (*Id*. (internal citation omitted).) Further, S&P confirmed that DTE has, on balance, over-earned its allowed ROE over the last several years. This is consistent with the Company's historical test year figures showing that it has over-earned its allowed rate of return by a figure of approximately $35.7 million on a revenue requirement basis. (*Id*. (internal citation omitted).)

In short, the Company has strong credit ratings resulting from lower risk utility operations benefitting from constructive credit support mechanisms and Michigan's existing regulatory framework. None of this indicates the Company has elevated risk or requires a ROE above what the Commission has previously approved.

b. The Company's proposed capital structure is unreasonable and skews its ROE request.

The Company proposed a 51.5% equity ratio which is higher than its current equity ratio, counter to the Commission's former directives, and inconsistent with industry trends. (See Walters 4 Tr 1358-61 (internal citations omitted)). The Commission should therefore reduce the Company's equity ratio to avoid unnecessarily increasing customer rates. (*Id*.)

The Company's proposed equity ratio significantly exceeds that for the proxy group the Company used to support its ROE recommendation. (*Id*.; see Exhibit AB-5.) Further, it is diametrically contrary to the Commission's previous Order in U-20940, where it authorized an equity ratio of 51.0% and, in rejecting the Company's proposed 51.9% equity ratio, stated such a request "does not reflect an effort to move to a more balanced capital structure." *In the Matter of the Application of DTE Gas Co*, order of the Public Service Commission, entered December 9,

2021 (Case No. U-20490), pp 76-78. The Company's requested 51.5% equity ratio moves in the opposite direction of the Commission's explicit directive, as well as additional regulatory commission's recognition of the importance of aligning the cost of equity with capital structure.[13] (Walters 4 Tr 1258-61 (internal citations omitted)). As described in more detail below, while ABATE's proxy group in this case had an average common equity ratio of 44.4% (including short-term debt) and 50.0% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively, DTE's proposed ratemaking equity ratio of 51.50% (excluding short-term debt) exceeds that of the proxy group's equity ratio and is not reasonable for ratemaking purposes.[14] (*Id*.)

The Company's 51.5% proposed equity ratio therefore significantly exceeds the equity ratios of the proxy group and directly contradicts the Commission's prior direction for DTE to maintain a more balanced capital structure. As such the Commission should, consistent with its prior Orders, approve a permanent equity ratio for DTE of 50.0%.

[13] The Company's claims that "[a]fter accounting for short-term debt, the 51.5% equity ratio becomes closer to 50.0%" and "DTE Gas has a proportionally larger short-term debt balance than other Michigan utilities, so its capital structure is more impacted on an adjusted basis" are misplaced. (Lepczyk 4 Tr 2210.) The proxy group, which is used to assess the Company's cost of equity, has a lower equity ratio than the Company's requested level. As discussed here, excluding short-term debt, the Company's requested equity ratio is 51.50% while the proxy group's equity ratio is 50.0%. (See Walters 4 Tr 1361-64.) Similarly, as the Company points out, including short-term debt, the Company's requested equity ratio is closer to 50.0%, which compares to 44.4% for that of the proxy group. Regardless of how one looks at the capital structure, DTE's proposed equity ratio is higher than that of the proxy group which is used to estimate the cost of equity. (*Id*.)

[14] Staff's proposed equity ratio is similarly unreasonable. (See Walters 4 Tr 1413-14; Ufolla 4 Tr 1614.) While Staff indicated a 51% ratio would allow for a "smoother transition to a balanced equity ratio of 50% in a future case," a 51% equity ratio is hardly any transition at all. (*Id*.) Consistent with the Commission's direction and recent directive the Company's equity ratio should be set at 50% in this proceeding.

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 4 Tr 1361-64.) The proxy group utilized for ABATE's quantitative analyses is the same as that utilized by DTE with six exceptions. First, Chesapeake Utilities was removed as it, and its subsidiaries, are not rated entities by S&P or Moody's. (*Id*.) Credit ratings are a critical, independent assessment of total risk, and one of the most cited screening criteria used by rate of return analysts around the country. In addition, NiSource Inc. and Southwest Gas Holdings were removed for being parties to significant merger and acquisition ("M&A") activities in the last two years. (*Id*.) Importantly, although DTE used M&A activity as a screening criterion in developing its proxy group, it neglected to remove these companies even though they were parties to significant M&A transactions during the study period. (*Id*.) Finally, Artesian Resources Corp., Global Water Resources, and York Water Company were removed as they are not listed entities of the Water Utility Industry in the *Value Line Investment Survey*. (*Id*.) Companies not in the *Value Line Investment Survey* are not covered by a Value Line analyst and any reported growth rates for Companies no longer in the *Value Line Investment Survey* are the most recently reported growth rates from when that Company was in the *Value Line Investment Survey*.[15]

[15] Staff's proxy group is similarly flawed. (Walters 4 Tr 1414-18.) Specifically, Staff also erroneously included Chesapeake Utilities, NiSource, and UGI Corporation. (*Id*. (internal citation omitted).) As noted above Chesapeake Utilities and its subsidiaries do not have credit ratings and it acquired Florida City Gas, a natural gas utility in southern Florida, from NextEra Energy on November 30, 2023 for nearly $1 billion. (*Id*.) This transaction represents approximately 40% of its post-acquisition market capitalization and certainly affects its fundamental value. (*Id*.) Similarly, as noted above, NiSource was also a party to a significant transaction for $2.16 billion (i.e. 20% of its market capitalization) during Staff's study period. UGI Corporation should have been excluded as it has significant foreign operations in Europe. (*Id*.) Staff acknowledged it typically eliminates companies on the basis of lacking credit ratings and/or foreign investment, specifically Chesapeake Utilities and UGI. However, Staff also stated that it included them here

The proxy group developed by ABATE has average credit ratings of A and A3 from S&P and Moody's, respectively. Thus, the full proxy group's average rating of A from S&P is one notch higher than DTE's rating of A- from S&P and its average rating of A3 from Moody's is identical to DTE's rating of A3. (*Id*.) More specifically, the gas group has average ratings of A and A3 from S&P and Moody's, respectively. The rating of A from S&P is one notch higher than DTE's, while the Gas group's rating of A3 from Moody's is identical to the rating assigned to DTE. (*Id*.) The Water group's rating of A from S&P is one notch higher than DTE's, while the Water group's rating of Baa1 is one notch lower than DTE's rating of A3. (*Id*.) On balance, therefore, DTE's ratings are comparable to those of the proxy companies.

The proxy group also has an average common equity ratio of 44.4% (including short-term debt) and 50.0% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively.[16](*Id*.) Thus, while a ratemaking equity ratio of 50.0% is still higher than that of the proxy group, it provides a more comparable basis to estimate the cost of equity requested by DTE. As such, ABATE's proxy group is more reasonably comparable to DTE than that used by the Company and the Commission should reject its requested equity ratio.

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due to the limited number of proxy company candidates at this time. (*Id*.) This is not a reasonable basis for determining a comparable proxy group or ROE estimate, as Staff acknowledged when noting that the results for Chesapeake and UGI produced "nominally higher outputs from the DCF and CAPM." (*Id*.; Ufolla 4 Tr 1621-22.) Including these companies had a material and unreasonable impact on its model results, recommended range, and recommended ROE.

[16] The Company's claim that "Exhibit A-35, Schedule Y1, shows that the authorized common equity ratio approved by the state commissions for the peer group gas operating companies is 53.8% and consistent with the Company's request for an authorized equity ratio of 51.5%" is misleading. (See Lepczyk 4 Tr 2209.) Using the provided docket numbers in Exhibit A-35, Schedule Y1, the average authorized ROE for the same group is 9.58% and ranges from 9.10% to 10.25%. Of the 20 reported authorized ROEs from the set of rate cases provided by DTE, 10 are 9.50% or lower, 18 of them are below the Company's currently authorized ROE of 9.90%, and the remaining two ROE decisions are 10.0% and 10.25%. The Company's analysis is therefore incomplete and should be ignored. If the Commission gives any weight to it, it cannot ignore the authorized ROEs for the group.

d. Reasonable empirical models demonstrate a reasonable ROE for the Company is 9.45%.

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 Capital Asset Pricing Model ("CAPM"). Considering DTE's specific risk and the result of these analyses a reasonable ROE is 9.45%.

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 4 Tr 1364-67.) 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 August 5, 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.[17] (*Id*.) The dividend used was each proxy company's most recently paid quarterly dividend as reported in *Value Line*. (*Id*.) For dividend growth rates, in order 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

[17] The Company's claim that this approach results in "unnecessary volatility" is therefore inaccurate. (Villadsen 4 Tr 2577.) This approach is the best way to get a clear accounting of an average stock price to avoid anomalous disruptions which will skew results.

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 growth rate for the proxy group is 6.27% and the median growth rate is 6.43%. As shown in Exhibit AB-7, the average and median constant growth DCF returns for the proxy group for the 13-week analysis are 9.84% and 10.26%, 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 4.14%.[18] (*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 4 Tr 1368-69.) 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

[18] *Blue Chip Economic Indicators* projects a U.S. nominal GDP growth rate of 4.14% over the next 5 and 10 years. (Walters 4 Tr 1364-68 (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*.)

of earnings, dividends, earned returns on book equity, and stock issuances.[19] (*Id*.) As shown in Exhibit AB-9, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 5.27% and 4.53%, 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 8.80% and 8.80%, 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 4 Tr 1369-75.) 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

[19] While the Company objected to the use of *Value Line* as a source of an appropriate growth rate, it failed to provide sources other than *Value Line* which have estimates for each of the components used in the model. (Villadsen 4 Tr 2577.)

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 8.09% and 7.69%, respectively. (*Id*.) Considering these results along with those of the additional DCF analyses described above, a reasonable ROE based on the DCF results is between 9.01% and 9.41%. (*Id*.)

iv. Risk premium model.

This model is based on the principle that investors require a higher return to assume greater risk. (Walters 4 Tr 1376-80.) 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;[20] 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.[21] (*Id*.; Exhibits AB-12, AB-13, and AB-14.)

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

[20] The risk premium was estimated on an annual basis for each year since January 1986. (Walters 4 Tr 1376-80.) 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*.)

[21] The period of 1986 through 2021 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*.)

therefore assessed the five-year and ten-year rolling average risk premiums[22] 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.[23] (*Id*.)

The risk premium results from the method described above, and using 13-week and 26-week periods, are 9.96% and 10.21%, respectively. (*Id*.)

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 4 Tr 1380-90.) 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

[22] 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*.) Thus, the Company's claim that historical betas "fail[] to recognize that the systematic risk of utilities has changed during the last decade" is inapposite; these betas help provide important context without the bias of short-term distorting factors unlikely to be realized in the projected test year. (Villadsen 4 Tr 2542.) Further, DTE's lack of relative risk is addressed above.

[23] Further market evidence was also used when developing the risk premium analysis. (Walters 4 Tr 1376-80.) 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.

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 April 5, 2024.[24] (*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 9.15% to 10.80%. (*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

[24] 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 CAPM analysis. (Walters 4 Tr 1380-90.) The Company's claim that a long-term average of betas is "problematic" is therefore flawed. (Villadsen 4 Tr 2571.) 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.

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.

vi. A reasonable ROE for the Company should be no higher than 9.50%.

Based on these analyses, an appropriate estimate for the Company's current market cost of equity is within the reasonable range of 9.10% to 9.80%. (Walters 4 Tr 1390-91.) This recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model and the irrational assumption that Value Line's current beta estimates are reflective of current investor expectations. Based on an objective assessment of DTE's overall risk profile and the results of these analytical methods, an appropriate ROE for DTE is 9.45%, 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% ROE based on its perception of DTE's risk and several models which it applied to a sample group of natural gas and water companies. 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 4 Tr 2458.) As this ROE is excessive and unreasonable given DTE's 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 indicate the Company's required ROE is in the range of 8.3% to 10.6%. (Walters 4 Tr 1392-95.) Despite this range, DTE increased its market ROE estimate by adjusting its results upward in the range of 0.2%-1.7% 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 regulatory commissions throughout the country, including this one. This ATWACC adjustment

increases the Company's recommended range up to 10.0%-10.7%. (*Id*.) Without this improper adjustment DTE's own studies, with reasonable adjustments, would support a ROE well below 10.25%.

The Company calculated an ATWACC for each of its sample DCF and CAPM 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. (*Id*. (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, 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. The Commission cannot oversee the reasonableness and prudence of a utility's management decisions regarding its capital structure. Under the ATWACC theory, however, management decisions regarding capital structure can be skewed by changes in market value which change the market value capitalization mix. While the Company's management simply has no control over the market value capital structure, 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 clear path for

regulatory oversight of management's effort to maintain a balanced and reasonable 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 future earnings and cash flow outlooks for the utility, 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 also 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 hence 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 opportunity for utility investors, as if the utility were an unregulated affiliate. Inflating utility rates to provide this excessive earnings opportunity is unjust and unreasonable to ratepayers 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).)

The ATWACC is therefore inappropriate for use in 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 analysis contained further flaws and should be rejected. (Walters 4 Tr 1398-99.) First, DTE's recommendation 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 Full Sample is 7.2% and is assumed in perpetuity in DTE's constant growth model. (*Id*.) This growth rate exceeds DTE's projected growth rate of 3.9% for the US economy by approximately 85%. Such a growth rate is clearly unsustainable and defies economic logic.[25]

In addition, DTE erroneously removed several results from its DCF analyses which ultimately caused significant upward bias in its results. (*Id*.) Specifically, the Company removed

[25] Staff's DCF analysis included the same flaw, namely a proxy group average growth rate of 6.06%, which is 46% higher than the expected long-term growth rate of the US Economy of 4.14%. (See Walters 4 Tr 1416-17.) Had Staff more reasonably performed a multi-stage DCF model that considered GDP growth, its DCF results would be significantly lower.

what it determined to be low-end outliers, but not high-end outliers.[26] (*Id*) As DTE's DCF analyses include results as high as 16.0% and as low as 4.4%, a more reasonable estimate for the DCF analysis would be based on the medians of its unadjusted results of 7.2% (multi-stage DCF) and 9.7% (constant growth DCF). (*Id*.) The Company's alternative approach is unreasonable and should be rejected.

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

In addition to the adjustments described above, the Company's analysis proposed a financial risk adjustment to reflect a leveraged beta adjustment which added approximately 40 to 60 basis points to the base CAPM return estimates. (See Walters 4 Tr 1399-1403.) 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.[27] Assuming DTE's risk-free rate of 3.95% and market risk premiums of 5.72%

[26] The Company's reference to "screen[ing] out any results that are less than 1.5% above the cost of debt because . . . FERC eliminates observations below the Baa utility bond yield plus 20% of the FERC-based MRP (currently about 8%, so the threshold is 1.6 percent above the Baa yield)" is inappropriate here. (Villadsen 4 Tr 2579.) Neither the proxy group (on average) nor DTE Gas have Baa bond ratings. Further, the cost of equity should be above each company's cost of debt. The Company failed to establish what any of the proxy companies' actual cost of debt is. Rather, it used current bond yields for all utilities in a rating category (A or Baa) as generic plugs for each company. Finally, the Company failed to explain how an ROE estimate of 16.0% is somehow meaningful while lower results are meaningless.

[27] The historical average *Value Line* beta since 2014 is 0.75 and has ranged from 0.64 to 0.81. Prior to the recent pandemic, the high end of this range was 0.75. (Walters 4 Tr 1399-1404.)

and 7.17%, incorporating the historical average *Value Line* beta of 0.75 would produce CAPM results of 8.2% and 9.3% respectively. (*Id*.)

Further, 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 0.83 to 1.06 (without taxes) and 1.01 (with taxes) for the Full Sample. (*Id*.) Thus, the Hamada model produced CAPM results in the range of 9.7% to 11.5% and ECAPM results in the range of 9.7% to 11.5% for the Full 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's regression-derived risk premium estimate of 6.26% for gas utilities is significantly higher than the equity risk premiums realized in 2023. (Walters 4 Tr 1403-05.) Specifically, the Company's regression analysis estimated an equity risk premium that is nearly a full percentage point higher than what was realized in 2023. (*Id*.) This is inconsistent with expectations for 2024. As Regulatory Research Associates explained in a recent report, the equity risk premium is expected to narrow in 2024 relative to 2023 for several reasons as "regulators navigate the ongoing energy transition and potential affordability challenges posed by higher interest rates and rising costs." (*Id*. (internal citation omitted).) The Company's claim that a regression approach "takes into account the relationship between the risk premium and interest rates" is therefore irrelevant; DTE's risk premium is significantly askew from the actual evidence of recent risk premiums. (Villadsen 4 Tr 2542, 2581.) As such the Company's risk premium analysis is unreliable and the recommended ROE based thereon should be rejected.

E. The Company's recommended CCOS is unreasonable and should be rejected.[28]

The Company filed two CCOSS in this case, including a Preferred CCOS and Alternative CCOSS. As the Preferred CCOS does not allocate costs in accordance with how customers cause DTE to incur them the Commission should reject the Company's proposal.

[28] This issue is addressed at York 4 Tr 1270-1308; Revere 4 Tr 1669-73; Krause 4 Tr 1725-32; Krysinski 4 Tr 2176-78.

1. A Design Day Demand cost allocation best reflects DTE's cost to serve its various customer classes.

The Company's Preferred CCOS filed in this case, which utilized a Peak & Average ("P&A") method of allocating transmission and distribution capacity costs, resulted in increases well above the system average for Rate XLT, Rate XXLT, and Exelon. (See York 4 Tr 1270-92.) These results follow from the inaccuracy of the Company's Preferred CCOS, which does not allocate transmission and distribution main capacity costs in accordance with the load characteristic that drives DTE's investment in transmission and distribution main capacity. (*Id*.) An accurate CCOS based on the Design Day Demand method of capacity cost allocation demonstrates instead that a rate decrease is necessary for certain transportation classes to reach cost of service. (*Id*.)

The flaws in the Company's Preferred CCOS are inherent in its use of the P&A method of allocating costs. These flaws stem from the P&A method's tempering of costs between high-load factor and low-load factor customers, meaning the allocation method distorts the accuracy of the Company's CCOS models by introducing rate impact considerations into allocating costs. Stated differently, the P&A method is not a pure cost allocation method as it artificially produces smaller increases for lower-load factor customer classes than the utility's actual cost of service, relative to a purely demand-based allocation method. (*Id*.) Instead of inappropriately attempting rate moderation within a CCOS, the Company should instead address any concerns regarding the magnitude of class rate increases in the subsequent class revenue allocation and rate design steps. By contrast, the Company's proposed cost unreasonably deviates from actually allocating costs to customers that cause them and should be rejected.

As an overview, the P&A allocation method consists of weighing two system load characteristics: the Design Day Demand allocator (weighted by 1 minus the system load factor)

and the Average Demand (or annual volume) allocator (weighted by the system load factor). (*Id*.) While the Commission has previously approved the P&A method's approach to compromising between the interests of high and low load factor customers, this is not an application of cost causation principles. Rather than reflect cost-of-service, the P&A allocation factor instead over allocates transmission and distribution main capacity costs to high-load factor customer classes and under allocates these main capacity costs to low-load factor customers. (*Id*.) Thus, the P&A allocator does not align with how DTE incurs the transmission and distribution main capacity costs it incurs to provide firm service to its customer classes.[29]

Costs should be allocated based on how DTE actually designs and operates it system; i.e., how it incurs costs. While transmission and distribution mains are used to provide service every day of the year including the peak day, delivery main capacity must also be able to meet the system Design Day Demand. (*Id*.) Thus, the system's main capacity is designed and built to serve the system's Peak Day, or Design Day Demand. Stated differently, the Company's costs are incurred to and based on its ability to serve its Peak Day demand. Measures of utilization (e.g., Average Demand, or annual throughput) therefore have no bearing on how DTE incurs delivery capacity cost. (*Id*.) In other words, while the Company must incur costs to construct the system such that it can serve its Peak Day demand, the inverse (i.e., incurring costs to construct the system such that it can serve average load) is not true. As such costs should be allocated in accordance with the

[29] On this point it's worth noting that large energy intensive customers are aware of the cost allocation methods used in different regulatory jurisdictions. (See York 4 Tr 1277.) To remain competitive within their industries and across the jurisdictions in which they operate, these customers make investment decisions based on that knowledge. The adoption of cost allocation methods that more accurately measure each customer class's cost of service, such as has been done in Manitoba, Missouri, and Pennsylvania, is therefore relevant and important to Michigan's ability to attract and maintain large customers and attendant economic development. (*Id*.)

former system design requirement which causes the utility to incur its costs, not the latter, which does not.

The Company confirmed the reality that its system is designed (and it incurs costs) in accordance with its Peak Day demand. Specifically, while transmission and distribution main capacity is designed to meet Peak Day demand, the demands of all rate classes, and the system, every other day of the year are simply met by varying the pressure and amount of gas in the mains which are built to satisfy that former Peak Day demand requirement. (*Id.*; Exhibit AB-1.) Thus, the fixed cost of transmission and distribution main capacity designed to meet the system peak demand remains the same every day of the year, irrespective of operating pressure and capacity utilization of the mains. There is therefore no causal link between the cost of transmission and distribution main capacity and annual throughput; these costs are instead entirely related to the system's Peak Day design. (*Id.*) Staff's argument that "it is only the A&P method that properly captures the various ways in which the costs associated with the distribution system are caused by the classes" is therefore inaccurate.[30] (Revere 4 Tr 1671-73.) This claim appears to be based on Staff's philosophy that "cost causation is a function of both design and usage," despite the fact that DTE explicitly explained that average usage has no impact on its system design costs. (Krause 4 Tr 1730.) The allocation recommended above assigns DTE's customers the costs they cause the

[30] Staff's assertion that it "does not agree that the A&P allocator 'primarily' allocates costs on volume based on how the word is used in common parlance" because "the A&P allocator (as calculated by the Company) allocates 64.236% of any cost it is applied to on peak day demand, and thus primarily allocates on peak day demand" ignores the actual cost allocation for the transportation classes. (Revere 4 Tr 1672.) Specifically, Staff's reference to 64.236% represents the weight that each class's peak day demand gets in the calculation of the composition P&A allocator. In other words, that is 1-system load factor. Staff is ignoring the fact that average demand comprises 86% of the peak day allocator for XXLT, and 76% of the peak day allocator for XLT. This is addressed by the discussion and diagram below. Mathematically the average demand represents about 91% of the composite P&A allocator for XXLT, and 84% for XLT. Neither the Company nor Staff addressed these figures or the calculation used to determine them.

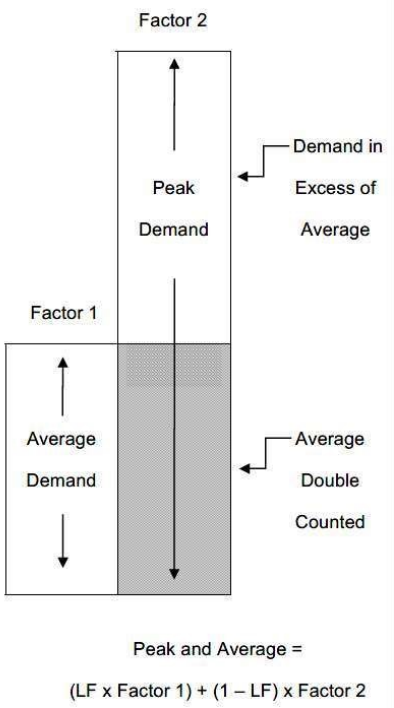
utility to incur, while the A&P method, as Staff acknowledged, is meant to represent a "compromise or tempering" of the cost allocation resulting from a strictly causation-based method. (Revere 4 Tr 1671-73.) Whether or not Staff would like to describe this approach to moderating cost increases as "artificial," it is not cost-based and is inconsistent with cost-of-service principles. (*Id*.) As Staff acknowledged, the Peak Day Design method is one of "the most commonly used demand allocations for natural gas distribution utilities" and allocates costs in the manner DTE incurs them, rather than the "compromise" recommended by Staff. (Krause 4 Tr 1728-29.) Indeed, Staff's claim that high and low load factor customers "use the distribution system differently" has nothing to do with how the Company incurs costs. As such this concern is irrelevant to allocating costs based on their causation. (*Id*.)

The fundamental principle of cost causation is that costs should be allocated based on how the utility is forced to incur them. Because the Company's mains costs are not driven by Average Demand, or annual volume, a purely cost-causation-based allocation of transmission and distribution mains should not include a volumetric component. (See York 4 Tr 1270-92.) The volumetric component of the P&A allocator (the Average component) which results in higher-load factor customer classes being allocated main capacity cost which they don't cause; i.e., that is not incurred to provide service to them, is therefore inappropriate and inconsistent with establishing cost-of-service rates.

The Design Day Demand method instead accurately reflects how DTE incurs costs to design its system. Indeed, the Company confirmed that its system is designed to provide service at design day peak volumes, that it does not use load factor when determining transmission facilities required by any DTE customer, and the cost to construct distribution and transmission mains is not related to annual volume delivered. (*Id*; Exhibit AB-1.) The Design Day Demand

method reflects these realities and the manner in which the Company incurs costs. The cost allocation recommended by Staff does not.

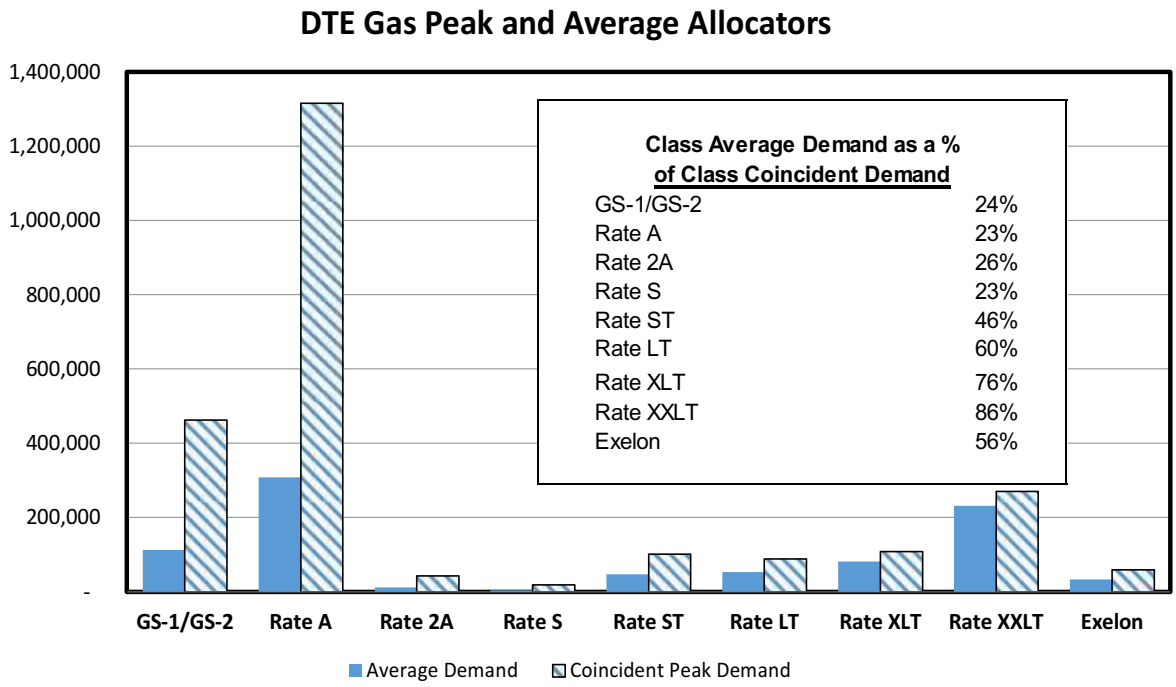
Indeed, contrary to allocating customers the costs they cause the utility to incur, the P&A method is a largely volumetric allocation factor as it counts Average Demand twice in the cost allocation: once in the Average Demand component and again in the Peak Demand component. (*Id*.) As can be seen in the two-step process of calculating the P&A factors below, the impact of using the P&A method is therefore the over-allocation of capacity costs to high-load factor customers. That is because the first step in the P&A method is to determine the Average Demand component, after which that Average Demand is double counted in the next step where each class's contribution to the system's Peak Demand is determined. In this second step, the P&A method considers the entire Peak Demand, including the Average Demand again:



Here the Average Demand (Factor 1) is weighted by the system load factor ("LF"). Peak demand (Factor 2) is weighted by (1 – LF). The two weighted demands are added together to arrive at the

P&A allocation factor. As a result, arithmetically, Average Demand receives a full weight of 1, while demand in excess of the average is weighted less than 1 (i.e., by (1 – LF)). (*Id.*)

The consequence of this flawed allocation method in the context of DTE's cost allocation is evidenced below. Specifically, class Average Demand constitutes 86% of coincident demand for the Rate XXLT class, versus 23% for the Rate A class. Further, in total, the Average Demand (throughput) component for Rate XXLT represents about 91% of the P&A allocation factor.[31] The Average Demand component for Rate XLT represents 84.4% of the P&A allocation factor.[32] Thus, the P&A allocation factor largely allocates fixed capacity costs on the basis of Average Demand (i.e., annual throughput or volume) (*Id.*; see Exhibit A-16, Schedule F1.2, p 3):



[31] System load factor of 35.8% + (86% x (1 – 35.8%)) = 90.95%.

[32] 35.8% + (76% x (1 – 35.8%)) = 84.38%.

Thus, while DTE explained that "[f]rom a cost of service perspective, it is assumed that the system is designed to provide service at design peak day volumes" and that "the cost to construct distribution mains is not related to annual volume delivered" and "the cost to construct transmission mains is not related to annual volume delivered," Staff's proposed cost allocation would allocate customers a significant amount of costs based on volume. (*Id.*; Exhibit AB-1.) This is directly contrary to the way the Company incurs costs. Indeed, the fact that the P&A method does not appropriately align with system design and cost causation has been recognized in multiple additional jurisdictions, including Manitoba, Canada, Pennsylvania, and Missouri. (*Id.* (internal citation omitted).) The latter two explicitly noted that the second step of the method redundantly reallocates average usage a second time. This is patently unreasonable and inconsistent with the manner in which the Company incurs costs.

Again, DTE incurs capacity cost to meet the total Design Day Demand of all customers on its system. To accurately reflect cost-causation every class should therefore be assigned the same system average unit cost of capacity. The P&A allocation method does not accomplish this. Instead, it allocates an above-system average unit cost of capacity to higher-load factor classes and allocates a below-system average unit cost of capacity to lower-load factor classes. Thus, in contrast with the Design Day Demand's reflection of how the Company actually incurs costs, the P&A method instead operates to level out and compromise between customer classes in defiance of cost-of-service principles. (*Id*) Thus, the transmission and distribution main capacity costs allocated to each class using the P&A allocation method do not align with how customers cause the costs of capacity DTE needs to provide firm service to the lower-load factor customer classes every day of the year, including the peak day. (*Id.*) With the most accurate cost of service study, like that recommended by ABATE, the Commission can more accurately assess whether any

customer class is subsidizing any other. This will give the Commission important information to ensure that all rate classes are treated fairly, and that rate adjustments move rates toward cost of service. (*Id*.)

Specifically, as noted above, the Design Day Demand method assigns the system average cost of transmission plant in-service capacity to all classes, consistent with cost-causation. This should be the guiding principle of conducting a CCOS; costs should be allocated in accordance with the way DTE incurs costs to design its system to safely provide firm service to its firm customers every day of the year. Any consideration of rate impacts resulting from any certain customer classes being moved to cost of service can be mitigated through the revenue allocation step of the overall rate design process. (*Id*.) Here, DTE has explained that it designs its system capacity to meet the Design Day and Design Hour Demands of its customers. (*Id*.) Therefore, consistent with cost-of-service principles, the Design Day Demand allocation method is the most appropriate cost allocation method to allocate capacity costs to DTE's customer classes. (*Id*.; see Exhibit AB-2.)

Alternatively, if the Commission does not support a purely demand-based allocation of capacity costs, the Average and Excess ("A&E" or "AED") method is more reasonable and more accurate than the P&A method. (*Id*.) The AED method is similar to the P&A method, as they both include a component based on average demand that is weighted by the utility's system load factor and a measure of each class's peak demand. (*Id*.) In the second component (i.e. peak demand), however, the AED allocator reflects the difference between each class's non-coincident peak demand and average demand (i.e., excess demand) without redundantly including average demand again. (*Id*.) As such the AED method does not suffer from the P&A method's inherent flaw of

counting average demand twice. (*Id*.) This better aligns the results of the AED method with cost causation.

In this case it is clear that Design Day Demand drives DTE's costs and would produce the most accurate measure of the Company's cost of providing service to each class. To the extent that the Commission prefers to continue relying on a partial energy-weighted method, however, the AED approach would be more accurate and reasonable than the P&A method. (*Id*.) As such, if the Commission does not elect to adopt the Design Day Demand method, it should direct DTE to provide an AED CCOS for consideration in its next rate case.

2. Staff's objections to the A&E Method are misplaced.

As noted above, a Peak Day Demand allocation best aligns costs with causation. Regarding ABATE's alternative proposal, to use the A&E method, Staff claimed that the A&P method does not double count average demand when allocating excess demand costs and the A&E method would allocate costs in a way that does not reflect customers' average use of the system. (Krause 4 Tr 1726-32; Revere 4 Tr 1672-73.) As neither of these points is correct the Commission should disregard Staff's objections.

Staff first asserted that under the A&P method "[o]nly a portion of the peak day could be considered double counted" and the "average could be determined using the 364 days other than the peak day" such that "the average gas on the peak day would not be double counted." (See Krause 4 Tr 1726-32.) This is an inaccurate characterization of the double counting problem. The A&E method does not remove the peak day from the average calculation, instead it removes the peak day from the excess element of allocation. (See York 4 Tr 1270-92.) Considered in the context of the figures above, Staff's argument is essentially to remove only a tiny sliver from Factor 1. The A&E method, however, is based upon removing the entirety of Factor 1 when determining

excess demand to be allocated (Factor 2), as that Factor 1 is already incorporated into the average demand to be allocated (*Id*.).

Similarly, Staff's citation to the Commission's October 28, 1993 Order in Case No. U-10150 misses the point of ABATE's alternative proposal to use the A&E method. While that Commission Order noted that "peak day load alone is insufficient to pay for the cost of building the plant, and off-peak service alone is not sufficiently desirable to many customers to allow for rates sufficient to recover the costs of building the plant," ABATE's proposal does suggest costs be allocated in this manner. (See Krause 4 Tr 1720 (internal citation omitted).) As explained above the average component of the A&E method allocates costs in a manner that reflects that the gas distribution system is required to provide service to customers in every day of the year. (See York 4 Tr 1270-92.) In other words, there is no emphasis or prioritization of off-peak service, the allocator's calculation of excess demand simply excludes the average demand which is already separately accounted for. Further, while that Order claimed that the proposal at issue in that case "would have the Commission allocate the entire cost of the 'plant' to users of the peak day service product, because the whole plant is needed to produce that product," that is not ABATE's alternative proposal here. (See Krause 4 Tr 1728-32.) Instead, the proposed A&E method incorporates demand. (York 4 Tr 1270-92.) Staff's attempts to rebut a cost allocation approach which ABATE has not recommended are irrelevant and should be disregarded. The A&E method ABATE alternatively recommended incorporates both average demand and excess demand in a manner which reflects how customer classes cause the Company to incur its related costs better than the P&A method.

Staff's focus on compromising between customer interests using the COSS, regardless of adhering to actual cost causation principles, is evident in its testimony. For instance, Staff asserted

that ABATE utilizes "a measure that has not been shown to have any connection to cost causation," that it "breaks the link between system load factor, peak, and usage that the A&P method relies on," and Staff "is uncertain what the justification for using system load factor for weighting is when the peak used to calculate that load factor is no longer part of the equation." (Revere 4 Tr 1672-73.) As demonstrated above the A&E method more accurately reflects cost causation than the P&A method. (York 4 Tr 1270-92.) It identifies the base amount of capacity that would be needed if all customers used gas at a constant rate (i.e. 100% load factor), and allocates that capacity on average demand, which is the same approach as the P&A method recommended by Staff. (*Id*.) The A&E method then identifies the amount of capacity needed to meet each class's peak demand in excess of the base (i.e. Average) demand. This portion is allocated in proportion to the difference between each class's non-coincident peak demand and average demand. (*Id*.)

Contrasted with the P&A method, this method assigns a greater amount of capacity cost to weather sensitive customer classes whose peak demand demonstrates the greatest variability relative to average demand. This is appropriate because the excess capacity that exists on the system on a non-peak day is held in reserve to meet the peak day demand of weather sensitive customers. In other words, those customers cause those costs. As such, cost-of-service rates should allocate those costs to those customers. Further, regarding Staff's claim as to the "link between system load factor, peak and usage that the A&P method relies on," as noted above measures of utilization like load factor and average demand are not linked to cost causation. (*Id*.; Revere 4 Tr 1672-73.) In addition, as Staff noted, the NARUC Manual provides that "[t]here is a wide variety of alternative formulas for allocating and determining demand costs, each of which has received support from some rate experts" and "[n]o method is universally accepted." (See Krause 4 Tr 1728.) The P&A method, rather than reflect true cost causation, "tempers the apportionment of the

costs between high and low load factor customers." (*Id*.) Ultimately, therefore, the P&A energy weighting is established based on judgement. Thus, the same load factor as used in the weighting of the P&A allocator could be used for A&E, or Staff could investigate an alternative.

Further, Staff's claims that the A&E method "fails to recognize that delivering the 'average' amount of gas on a peak day (or during a class' NCP month) does not result in the same costs as on an average day," and they "fail to recognize that average usage is really another way of incorporating throughput, or the entirety of gas used throughout the year, of which the average used on one of the days of the year represents an exceedingly small portion" are similarly confused in the context of the A&E cost allocation methodology actually proposed here. (Revere 4 Tr 1672-73.) Specifically, these assertions appear to be based on a claim that the average considered in the A&E methodology is somehow different from that in the A&P methodology. As explained above, these components are mathematically identical; that is, they are both based on average annual throughput and weighted using the system load factor. (York 4 Tr 1270-92.) Thus, the costs to deliver an "average" amount of gas on a peak day as compared to the costs on an average day (whatever differences there may be are not discussed by Staff) are irrelevant. Furthermore, the average usage incorporated in the A&E method by definition incorporates annual throughput. If Staff sees this as a flaw in the A&E method, this same flaw also exists in the A&P method Staff recommended.

Staff's points are therefore misdirection and mischaracterizations of the A&E method actually alternatively recommended by ABATE. As set out above the A&E method better aligns cost allocation with cost causation than the P&A method. As such, in the event the Commission does not adopt the Peak Day Design method, it should adopt the A&E method for the reasons set forth above.

3. Staff's proposed rate design is not consistent with cost-of-service principles.

Staff utilized DTE's Alternative CCOSS to recommend how revenue responsibility should be shifted between transportation schedules when adjustments must be made to maintain the current breakeven points. (Revere 4 Tr 1662-64.) Staff's proposed revenue requirement allocation is not consistent with cost causation and should be rejected.

Specifically, while Staff's adjusted version of DTE's Preferred CCOSS shows that an increase of about $3.5 million (11.3%) is necessary for the XXLT class to reach cost of service, Staff proposed a $9.9 million increase (i.e., 31.5%, or 7.55x the system average), based on the results of the Alternate CCOSS. (*Id*.) Thus, despite Staff's proposed revenue deficiency being about 34% less than DTE's, Staff's revenue spread would assign approximately $6.3 million *more* to the XXLT class than indicated by the Company's Preferred CCOSS model, and about $5.3 million more than proposed by the Company in its recommended revenue apportionment. (*Id*.; York 4 Tr 1302-06.) This result is unreasonable and does not reflect cost-of-service.

First, Staff's proposed revenue apportionment for the transportation classes is based on the results of two P&A CCOSS models with fatal flaws, as described above. Staff's proposed revenue allocation is therefore inherently unreasonable and does not align cost allocation with customers' cost causation. Further, the transportation rate structures must be refined to ensure that customers served at different service levels (e.g., transmission, high-pressure distribution, or low-pressure distribution) are allocated the costs associated with the infrastructure used to serve them. (*Id*.) Staff's proposed rates do not address this significant issue and result in customers paying costs for which they are not responsible. Within the XXLT class for example, customers served directly from transmission mains or high-pressure distribution mains would be required to pay for portions

of the low-pressure distribution system that are not and physically cannot be used to provide them service. (*Id*.) This is clearly unreasonable and inequitable.

Thus, while the Alternate CCOSS' more granular cost allocation distribution would better reflect cost-causation than DTE's Preferred CCOS, given the differences in the infrastructure used to provide service to the handful of customers within the XXLT class, it still contains material deficiencies which would result in customers paying for infrastructure they don't use. These flaws require refinement to ensure that distribution main costs are accurately assigned to the XXLT class. For instance, as noted above, the Alternate CCOSS relies on the P&A method, which results in an inaccurate measure of the cost of providing service to each class. Further, the Alternate CCOSS reflects a significant change in the allocation of distribution mains costs relative to prior cases. Reliance on this method to allocate costs produces significant, unjust, and unreasonable rate impacts for certain classes like Rate XXLT. In addition, because peak day demand data is not available by service level within each class, the Company simply assumed the portion of each class's peak day demand served from transmission and high-pressure distribution mains is equal to the portion of each class's annual throughput served by each type of main. This assumption does not result in a reliable or accurate allocation of costs that rely on customer class contributions to peak demand. (*Id*.) Before allocating costs to Rate XXLT customers DTE therefore needs to review the infrastructure used to actually provide service to those customers. (*Id*.) It may be the case that a very limited portion of system distribution mains are used to serve customers in this class, such that an allocated slice of total system distribution mains is not appropriate. The fact that this fundamental element of cost causation (i.e., that customers should be allocated the costs they cause) is not clear here demonstrates that this approach to cost allocation is not reasonable and should be rejected.

Concerns similar to these were raised in DTE's last natural gas rate case. (See Case No. U-20940, 5 Tr 265-76.) Despite those concerns persisting into and not being addressed in this case, however, Staff kept each transportation schedule's share of the total transportation revenue requirement static between the results of the CCOSS using the current methods of allocation and Staff's Alternate CCOSS to the extent possible while conducting rate design. (*Id*.) Thus, rate design improvements lacking in Staff's recommendation are needed to ensure that Rate XXLT customers are only assigned the cost of distribution infrastructure they actually use. (*Id*.)

A more appropriate cost allocation better reflecting cost-of-service for these customers would entail no rate change for Rate XXLT and bringing Rate XLT to cost of service based on a Design Day Demand CCOSS with a below-system average increase (0.12x the system average based on Staff's proposed revenue deficiency). (*Id*.) Alternatively, given the distance from actual cost-of-service represented by the Company's CCOSSs, it would be more reasonable to approve a system average increase across all classes, provided the Company commits to provide a properly conducted Average and Excess Demand ("AED") CCOSS in its next rate case. (*Id*.) This alternative revenue apportionment would reflect a compromise between the P&A and Design Day Demand CCOSS until an AED CCOSS is conducted, and until such time as concerns regarding the Alternate CCOSS have been addressed. Without the information identified above neither of DTE's CCOSSs is a reasonable reflection of cost-of-service rates and should not be approved.

Beyond its misalignment of costs and their causation, Staff's proposed rate design is also inconsistent with the purpose of DTE's transportation rate schedule. Specifically, Rate XXLT is designed to retain the very largest End Use Transportation ("EUT") customers that would otherwise bypass DTE's system and take service directly from interstate transmission pipelines. (*Id*.) Their size, energy consumption, and location near interstate pipelines afford these customers

the opportunity and means to make an investment to bypass DTE's system and cease being DTE customers. (*Id*.) Staff's rate design for this and the additional transportations rates is not meant to reflect cost-of-service, it is meant to preserve existing break-even points between rate schedules. (York 4 Tr 1306-08; Todd 4 Tr 1639-42.) Indeed, Staff acknowledged its rate design considers the percentage share of the revenue requirement to be collected from each transportation schedule based on the Alternate CCOSS, which does not reflect cost-of-service. (*Id*.) Again, while for Rate XXLT Staff's CCOSS contained in Revised Exhibit S-6 results in a purported cost-based increase (including over-allocations resulting from the P&A method) of about $3.5 million (or 11.3%), the Alternate CCOSS would assign an additional $6.3 million to Rate XXLT for a total proposed increase of $9.9 million (or 31.5%). (*Id*.) This is not justified by cost causation principles and, as noted above, would result in these customers paying for costs they do not cause. Contrarily, for the Large Transportation ("LT") and XLT rate schedules, Staff proposed to reduce the customer charges from their current levels. (*Id*.) Again, this is inappropriate given that DTE's cost-of-service is largely comprised of fixed costs, and the transportation rate structure does not include a demand charge for fixed cost recovery. In addition, Staff did not propose to modify the transportation rate structure to address the intra-class allocations of distribution main costs. (*Id*.) Such revisions are necessary to properly recover the costs of distribution mains from the customers within the various transportation schedules who use that part of the system and cause those costs.

Staff's proposed rate design is therefore unjustified and unreasonable. Again, despite Rate XXLT's purpose of maintaining customers which could otherwise bypass DTE's system altogether, Staff's recommendation would assign an additional $6.3 million to Rate XXLT based on an Alternate CCOSS which does not reflect cost causation. (*Id*.) This is inconsistent with the objective of providing competitive, cost-based rates to customers that have the potential to bypass

the Company's distribution system altogether. Given the significant flaws in Staff's proposal the Commission should maintain the existing transportation rate structures while requiring rates be designed to reflect the revenue apportionment outlined in following table (*Id.*):

REVISED TABLE JAY-2-RT

Design Day Demand CCOSS vs. Proposed Revenue Apportionment ($000)

Line	Rate Schedule	Total Revenues at Current Rates (1)	Preferred CCOSS* Net Increase / (Decrease) to Reach Cost of Service Amount (2)	Percent (3)	Index (4)	Alternate CCOSS* Net Increase / (Decrease) to Reach Cost of Service Amount (5)	Percent (6)	Index (7)	ABATE Proposed Net Increase / (Decrease) Amount (8)	Percent (9)	Index (10)
1	GS-1/GS-2	$ 355,402	$17,018	4.8%	1.14	$18,974	5.3%	1.28	$17,018	4.8%	1.14
2	Rate A	1,125,079	73,632	6.5%	1.56	83,169	7.4%	1.77	49,394	4.4%	1.05
3	Rate 2A	35,363	328	0.9%	0.22	623	1.8%	0.42	328	0.9%	0.22
4	Rate S	10,575	886	8.4%	2.00	992	9.4%	2.24	464	4.4%	1.05
5	Rate ST	46,063	(12,683)	-27.5%	(6.58)	(13,723)	-29.8%	(7.12)	-	0.0%	-
6	Rate LT	30,967	(6,704)	-21.6%	(5.17)	(12,133)	-39.2%	(9.36)	-	0.0%	-
7	Rate XLT	29,299	146	0.5%	0.12	(10,155)	-34.7%	(8.28)	146	0.5%	0.12
8	Rate XXLT	31,324	(5,272)	-16.8%	(4.02)	308	1.0%	0.23	-	0.0%	-
9	Exelon	13,145	2,839	21.6%	5.16	2,135	16.2%	3.88	2,839	21.6%	5.16
10	Total	$1,677,217	$70,189	4.2%	1.00	$70,189	4.2%	1.00	$70,189	4.2%	1.00

Sources and Notes:

* Uses Staff's revised CCOSS models and replaces the P&A allocator with Design Day (i.e. Peak Day) Demand.

Further, the Commission should maintain the transportation customer charges recommended by DTE and modify the volumetric distribution charges accordingly. This approach will better reflect DTE's cost-of-service and result in more appropriate and reasonable rates.

III. 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

By: Stephen A. Campbell

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Date: July 16, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **DTE GAS COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority	)	Case No. U-21291
	)	ALJ Jonathan F. Thoits

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF WAYNE)

Stephen A. Campbell, being first duly sworn, deposes and says that on June 16, 2024, he did cause to be served the ***Association of Businesses Advocating Tariff Equity's Initial Brief,*** as well as this ***Proof of Service*** in the above docket, via electronic mail, to the persons identified on the attached service list.

Stephen A. Campbell

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SERVICE LIST
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