STATE OF MICHIGAN
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January 14, 2020

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Dear Ms. Felice:

Re: <u>MPSC Case No. U-20561</u>

Enclosed please find the ***Attorney General's Initial Brief,*** and related Proof of Service.

Sincerely,

Joel King Digitally signed by Joel King Date: 2020.01.14 23:22:15 -05'00'

Joel B. King
Assistant Attorney General

cc: All Parties

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

MPSC Case No. U-20561

ATTORNEY GENERAL INITIAL BRIEF

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Dated: January 14, 2020

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INTRODUCTION

The Attorney General of Michigan, Dana Nessel, by and through Joel B. King, Assistant Attorney General, files this Initial Brief before the Michigan Public Service Commission ("MPSC" or "Commission") to respond to DTE Electric Company's ("DTE," "DTE Electric," or the "Company") application seeking increased revenues for its electric business.

After reviewing the testimony, exhibits, and discovery conducted in this case and with the help of her expert witnesses, Mr. Roger Colton, Mr. Sebastian Coppola, and Dr. David Dismukes, the Attorney General concludes that the Company has a revenue deficiency for the projected test year of no more than $41.1 million. Additionally, the Attorney General makes other recommendations with regard to the Company's filing as laid out in this brief.

On July 8, 2019, DTE Electric Company filed an application requesting authority to increase its electric rates in the annual amount of $350.7 million and for other relief. A prehearing conference was held on July 31, 2019 before Administrative Law Judge (ALJ) Sharon L. Feldman. At the prehearing conference, the ALJ noted the intervention of the Michigan Department of the Attorney General ("Attorney General" or "AG"), and granted intervention to: the Association of Businesses Advocating Tariff Equity (ABATE), Citizens Utility Board (CUB), Energy Michigan, Inc., Foundry Association of Michigan, Local 223, Utility Workers Union of America (UWUA), AFL-CIO, Great Lakes Renewable Energy Association (GLREA), Residential Customer Group (RCG), Walmart, Inc., The

Kroger Company, Michigan Environmental Council (MEC), the Sierra Club, Natural Resources Defense Council (NRDC), Environmental Law and Policy Center/Ecology Center/Solar Energy Industries Association/Vote Solar (ELPC et al.), Soulardarity, Michigan Cable Telecommunications Association (MCTA), Central Transport, LLC, Central Transport, Inc., Crown Enterprises, Inc., the Detroit International Bridge Company, and Universal Truckload Services, Inc. The MPSC Staff (Staff) also participated.

The case schedule was discussed at the prehearing and was set by the ALJ on the record, as reflected in the August 1, 2019 Scheduling Memo.

STATEMENT OF FACTS

Pursuant to the schedule set at the prehearing conference, Staff and all Intervenors were required to file direct testimony on or before November 6, 2019. Any rebuttal testimony was due on or before December 2, 2019. Numerous parties filed either or both direct and rebuttal testimony.

DTE Testimony

DTE filed both direct testimony and rebuttal testimony to support its requested revenue increase of $351 million. In its proposal, the Company's requested rate relief spans the 12-month period from May 1, 2020 through April 30, 2021 ("projected test year" or "test year").

As part of its case, DTE is requesting a return on equity (ROE) of 10.50%, approval of a new Fixed Bill pilot program for the Residential D1 design, proposed tariff changes to certain interruptible service products, and a new low-income renewables pilot. DTE's requests represent an overall increase in rates of 7.1%, and a 9.1% increase for residential customers.

The Attorney General would like to note up front that DTE is making these requests and asserting that more than $350 million of annual rate relief is necessary a mere three months after the Company was granted a rate increase of $125 million in its last rate case, U-20162, and just over a year after the Company was granted approximately $65 million in its second-to-last rate case, U-18255. Additionally, this request is coming 29 months after the Company was granted a rate increase of approximately $184.3 million in its third-to-last gas rate case, U-18014. All of that adds up to significant cost increases for customers in less than two and a half years.

Importantly, DTE filed its "Filing Announcement" indicating its intention to file this electric rate case only 35 days after receiving an order and $125 million annual increase in U-20162. Additionally, per MCL 460.6a(6), utilities must wait at least 12 months from the date that its completed prior general rate case application was filed, to file a new general rate case application to increase rates. The application in U-20162 was filed on July 6, 2019, while the application in this case was filed on July 8, 2020. Based on these extremely tight timeframes, it is apparent that DTE Electric is in a continual cycle of preparing for and filing annual rate increase requests in the hundreds of millions of dollars. This does not allow the Company time to adequately consider its own needs or the tremendous burden it is placing on its customers. While this may be good for Company shareholders, it is an abuse of the ratemaking system, places a tremendous burden on Commission and Intervenor resources, and most importantly creates an ever-increasing demand on DTE Electric's customers, specifically its most vulnerable low-income customers.

Attorney General Testimony

The Attorney General sponsored the direct testimony and exhibits of three separate expert witnesses, Roger Colton, Sebastian Coppola, and Dr. David Dismukes, all of which was filed on November 6, 2019. Additionally, the Attorney General sponsored the rebuttal testimony and exhibits of Sebastian Coppola and Dr. Dismukes, which was filed on December 2, 2019. All of the Attorney General's direct and rebuttal testimony and exhibits were bound into the record without cross examination by any party on December 20, 2019.

Mr. Colton's direct testimony consists of 93 pages (9 Tr 3639-3733) along with 31 pre-filed exhibits. The Attorney General co-sponsored Mr. Colton's testimony along with MEC, NRDC, Sierra Club, and CUB.

Mr. Coppola's direct testimony consists of 123 pages along with an Appendix A, which contains his qualifications, (9 Tr 2954-3096) along with 42 pre-filed exhibits numbered AG-1.1 through AG-1.42. Mr. Coppola's rebuttal testimony consists of 8 pages. (9 Tr 3097-3105).

Dr. Dismukes' direct testimony consists of 43 pages along with an Appendix A, which contains his qualifications, (9 Tr 2829-2937) along with 12 pre-filed exhibits numbered AG-2.1 through AG-2.12. Dr. Dismukes' rebuttal testimony consists of 13 pages along with 1 pre-filed exhibit numbered AG-2.14. (9 Tr 2938-

2952). Certain portions of Dr. Dismukes' rebuttal testimony, along with a separate pre-filed exhibit were stricken at the beginning of the cross-examination hearing

In addition to the above, 20 additional exhibits, numbered AG-1.43 through AG-1.62, were admitted during cross examination.

Overview of the Attorney General's Direct Testimony

Roger Colton

After reviewing the testimony, exhibits, and discovery conducted in this case, Mr. Colton makes several recommendations and adjustments in direct testimony for the Commission to consider, pertaining to DTE's low-income programs and proposals. Mr. Colton has a long and distinguished history of researching and working on low-income utility issues all across the United States and Canada.[1]

By way of introduction and background, Mr. Colton first provides an in-depth overview and analysis of the affordability of DTE's electric bills, the prevalence of low income customers in DTE's service territory, and a look at the relationship between low-income status and revenue collection.[2] To the Attorney General's knowledge, this is the first time this information for the state of Michigan has been compiled in one place, which makes in an invaluable reference and provides a good look at challenges faced by low-income utility customers in the state.

[1] Ex. MEC-1; 9 Tr 3641-44.

[2] 9 Tr 3647-3703.

After that background, Mr. Colton provides recommended modifications to DTE's low-income bill payment program.[3] Specifically, he makes recommendations for ways in which DTE should expand and modify its existing low-income bill assistance program. While these will be discussed in greater detail later, at a general level Mr. Colton recommends 1) ways DTE should improve its bill assistance programs for all low-income customers, 2) modifications DTE should make for those customers in "extreme poverty," and 3) a new initiative for DTE customers who do not meet the income-eligibility for DTE's existing programs, but who are likely still in need.

Mr. Colton sponsors 31 pre-filed exhibits with his direct testimony, Ex. MEC-1 through Ex. MEC-31.[4]

Sebastian Coppola

After reviewing the testimony, exhibits, and discovery conducted in this case, Mr. Coppola concluded that the Company has a revenue deficiency for the projected test year of approximately $41 million. Mr. Coppola's conclusions are based on recommendations and related adjustments for the following major topics:

1. The level of Electricity Sales
2. The level of Operations and Maintenance expenses
3. Incentive Compensation
4. The level of proposed Rate Base and Capital Expenditures
5. The Company's Cost of Capital and Working Capital

[3] 9 Tr 3703-33.

[4] 9 Tr 3644-46.

6. The Fixed Bill Pilot
7. Depreciation Expense
8. Excess Deferred Taxes

He also explained that the absence of discussion on other matters in his testimony should not be taken as an indication that he agrees with those aspects of DTE's rate case filing. The narrow focus of his testimony is, instead, a consequence of focusing on priority issues within the available resources.[5]

Mr. Coppola summarized his conclusions, adjustments, and recommendations regarding these issues as follows:

> The Company filed for a base rate increase of $350.7 million. This rate increase represents an overall increase in rates of 7.1% with a 9.1% increase to residential customers. As a result of the rate case adjustments I propose in my testimony, the average residential customer should see an increase of less than 1% in their total bill.
>
> It is noteworthy to point out that during the five-year period from 2014 to 2018, the Company earned a return on common equity on a regulatory basis generally at or above the authorized ROE rate. In 2018, DTEE had an earned ROE of 10.1%.[6] That actual earned ROE is considerably higher than the Company's true cost of capital, which is significantly less than 9%.[7]
>
> …
>
> Based on my analysis of the Company's case, I have reached the following summary conclusions and recommendations:
>
> 1. I propose higher residential and commercial sales for $12.2 million of additional revenue.
> 2. I am proposing a lower level of Operations and Maintenance expenses of $128.8 million for the test year.

[5] 9 Tr 2960.

[6] Ex. A-2, Schedule A2, p 4.

[7] Ex. AG-1.17.

3. I propose a reduction in capital expenditures of $455.1 million and a reduction in rate base of $420.8 million, including adjustments to working capital.
4. I propose a reduction in depreciation expense of $17.0 million pertaining to the proposed reductions in capital expenditures.
5. I recommend an authorized rate of return on equity of 9.25%, which in comparison to the Company's proposed ROE rate of 10.50%, and higher short-term debt, results in a reduction in the revenue deficiency of $124.1 million.
6. I recommend that the Commission reject funding the Company's proposed fixed-billing pilot program.
7. I recommend that the Commission order the Company to establish a deferred regulatory account to record the actual excess deferred taxes amortized to expense annually versus the amount estimated in rates, with the balance of the account to be reflected in future rates. Furthermore, the Commission should direct the Company to file a letter under this case docket reporting the annual activity in the regulatory account.[8]

The O&M dollar adjustments broken down by topic are as follows:

Summary of O&M Expense Reductions	**Amount ($Millions)**
Inflation Expense Adjustment	$ 69.8
Power Generation	3.1
Distribution Operations	7.9
Credit/Debit Card Fees	4.7
Uncollectible Accounts Expense	2.1
Employee Incentive Compensation	38.0
Employee Benefits & Other	3.2
Total Reduction	**$ 128.8**

[8] 9 Tr 2963-64.

The Capital Expenditure and Rate Base dollar adjustments broken down by topic are as follows:

Summary of AG Disallowed Capital Expenditures		
		Amount (millions)
Contingent Capital Expenditures	$	17.7
Distribution Operations		
Emergent Replacement Programs		44.6
Customer Connections, Relocations, Other		27.4
Strategic Capital Programs		182.3
Power Generation		
Routine Projects		43.0
Non-Routine Projects		40.8
Information Technology		
Major Projects		54.9
Incentive Compensation		
Capitalized Amount		44.4
Total	**$**	**455.1**

As noted, these reductions equate to a reduction of the Company's proposed capital expenditures and deferred costs by approximately $310 million. These adjustments do not take into account adjustments by other parties in the case or additional adjustments that the Attorney General adopts in her Initial or Reply Brief. Mr. Coppola's recommendations will be addressed in depth later in the Attorney General's brief.

Dr. David Dismukes

After reviewing the testimony, exhibits, and discovery conducted in this case, Dr. Dismukes makes several recommendations regarding DTE's class cost of service study (CCOSS) and revenue distribution. Dr. Dismukes is a professor at LSU in

Baton Rouge, LA, and has decades of experience in the regulated and energy industries.[9]

In his direct testimony, Dr. Dismukes makes several recommendations. First, he recommends that the Commission utilize a set of alternative CCOSS methodologies that include: (1) use of a 4CP 50-0-50 cost allocation method for classifying and allocating costs associated with production plant facilities; (2) the use of a 12CP 100-0-0 cost allocation method for classifying and allocating costs associated with sub-transmission plant facilities, and (3) a non-coincident peak (NCP) cost allocation of costs associated with secondary-distribution plant facilities.

Second, Dr. Dismukes recommends that the Commission adopt a revenue distribution that reflects those alternative CCOSS recommendations. The ultimate revenue distribution effects of these changes will depend on the Commission's adopted revenue requirement for the Company.[10]

Finally, Dr. Dismukes recommends that if the Commission does not accept his proposed changes to the Company's CCOSS methodology, the Commission should limit the rate increase to the residential customer class to 1.15 times the overall system average increase. In the case of the Company's proposed revenue requirement increase, which recommends a 7.1 percent overall system average increase, this recommendation would limit any proposed increase to the residential

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[9] See Dr. Dismukes' Appendix A, 9 Tr 2874-2937.

[10] Based on the Company's proposed revenue requirement, the changes discussed earlier would result in the residential customer class receiving a 5.3 percent increase in rates, secondary customers receiving a 10.3 percent increase in rates, and primary customers receiving a 7.0 percent increase in rates.

customer class to 8.2 percent. Revenue increases displaced by this proposal would be allocated on an equal, proportionate basis, based on cost of service increase to the remaining classes.

This Initial Brief has been prepared based on available resources and therefore it focuses on the significant issues of concern summarized above. The Attorney General's silence on other issues should not be construed as approval of the Company's position. Additionally, the Attorney General reserves the right to address, in a Reply Brief, other issues raised by other parties in their Initial Briefs.

ARGUMENT

While examining the Attorney General's substantive objections and adjustments, the Commission should consider that DTE Electric bears the burden of proof to demonstrate that its proposals are just and reasonable. The obligation of proving any fact lies upon the party who substantially asserts the affirmative of the issue.[11] A plaintiff always has the burden of proving its cause of action.[12] In administrative cases, a party seeking relief must prove his, her, or its claim by a preponderance of the evidence.[13] Likewise, in MPSC Cases, a utility has the burden

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[11] *White v Campbell,* 25 Mich 463, 475 (1872).

[12] *Caruso v Weber,* 257 Mich 333; 241 NW 198 (1931).

[13] *Dillon v Lapeer State Home & Training School,* 364 Mich 1, 8; 110 NW2d 588 (1961), *and BCBSM v Governor,* 422 Mich 1, 88-89; 367 NW2d 1 (1985).

of proof by a preponderance of the evidence.[14] Given the nature of the burden of proof, the Commission may reject even uncontradicted evidence.[15] When the burden of proving a fact falls on one party, the other party does not have the burden of proving the opposite fact.[16]

In addition, as the Commission has previously explained and as has been clarified in prior proposals for decisions, the utility has an obligation to support its rate base projections in a general rate case:

> Section 6a (1) of Act 286, MCL 460.6a(1) provides that a utility "may use projected costs and revenues for a future consecutive 12-month period" to develop its requested rates and charges. As the Commission has discussed previously:
>
> In a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections. Given the time constraints under Act 286, all evidence (or sources or evidence) in support of the company's projections should be included in the company's initial filing. If the Staff or intervenors find insufficient support for some of the utility's projections, they may endeavor to validate the company's projection through discovery and audit requests. If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) the Staff, intervenors, or the Commission may choose an alternative method for determining the projection.[17]

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[14] *In re Michigan Gas Utilities Co,* MPSC Case No. U-7484, Opinion & Order dated 8-30-83, p 10, and *In re Detroit Edison Co,* MPSC Case No. U-8030-R, Opinion & Order dated 7-9-87, pp 16-17.

[15] *Woodin v Durfee,* 46 Mich 424, 427; 9 NW 457 (1881). *Accord, Yonkus v McKay,* 186 Mich 203, 211; 152 NW 1031 (1915), and *Cuttle v Concordia Mut Fire Ins Co,* 295 Mich 514,519; 295 NW 246 (1940).

[16] *S C Gary, Inc v Ford Motor Co,* 92 Mich App 789, 803-804; 286 NW 2d 34 (1979).

[17] September 8, 2016 Order in Case No. U-17895, p. 4, citing January 11, 2010 order in Case No. U-15768 et al., pp 9-10.

Therefore, before examining the Attorney General's recommendations and arguments, the Commission should consider that DTE bears the burden of proof to demonstrate that all of its requests, including its request for a rate increase, are just and reasonable. The following sections lay out the Attorney General's analysis of DTE's case and support for the Attorney General's recommendations. In this initial brief, the AG presents her arguments and discussion by witness, starting with Mr. Colton, moving to Mr. Coppola, and finishing with Dr. Dismukes. While Mr. Colton's and Dr. Dismukes' testimonies focus on discreet issues, Mr. Coppola's testimony provides a more full analysis of DTE's entire case.

Roger Colton

Mr. Colton's testimony focuses on low-income DTE customers and certain recommended modifications to DTE's programs and resources. The Attorney General adopts those recommendations and urges the Commission to adopt them as well.

At the beginning of his testimony, Mr. Colton analyzes and discusses low-income DTE customers generally, exploring the extent to which DTE's electric bills are affordable, or conversely, the extent to which they are unaffordable, to DTE's low-income customers.[18] This is an important discussion to have in the midst of DTE looking to raise residential rates by more than 9%. His testimony provides good background on DTE's more "energy insecure" customers. DTE estimates 1/5,

[18] 9 Tr 3647-48.

or approximately 20%, of DTE's customers live below the federal poverty line. DTE estimates that half of those customers need energy assistance. Mr. Colton's estimate is even higher. Mr. Colton then provides an important overview of affordability and how to measure it properly.[19] At base, affordability comes down to bills as a percentage of a household's entire income.[20] Through Mr. Colton's analysis of DTE's service territory and billing, he demonstrates that there is a serious affordability problem for customers in DTE's service territory.[21]

As noted in Mr. Colton's testimony, the goals of the recommendations on this topic are

- To enable and empower as many DTE customers as possible to pay their bills,
- To make sure that DTE customers can keep their utilities on,
- Reduced bad debt and reduced working capital expenses for DTE,
- To reduce the time, effort, and money spent by DTE trying to track down delinquent accounts.[22]

One other important conclusion that Mr. Colton demonstrates is that "providing adequate bill assistance to low-income customers will help improve payment outcomes for DTE Electric, thus creating correspondingly positive impacts on reducing the costs associated with nonpayment that are ultimately charged to

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[19] 9 Tr 3647-54.

[20] 9 Tr 3647.

[21] 9 Tr 3651.

[22] 9 Tr 3656.

ratepayers.[23] This is important to note. There is solid, long-term evidence that providing adequate, well-structured bill assistance to low-income customers of a utility is advantageous to both the customers *and* the utility as a whole.[24]

<u>Recommended Modifications to DTE's Low-Income Bill Payment Program</u>

After the extended background provided by Mr. Colton, he then provides specific recommended modifications to DTE's Low-Income Bill Payment Program, along with some ideas for an entirely new program. His recommendations are based on his national analysis, DTE-area analysis, and his application and comparison of the two.

First, Mr. Colton provides a good overview of DTE's three existing low-income bill assistance initiatives, the Low-Income Self-Sufficiency Program (LSP), Low-Income Assistance Credit (LIA), and the Residential Income Assistance (RIA).[25] He spends time examining and explaining the differences between the three programs, including participation rates in the programs and the performance of those participating.[26] He also performs analyses and provides discussion on what "success" looks like in DTE's programs.[27]

<u>Specific Recommendations</u>

Mr. Colton's specific recommendations, which the AG adopts, include:

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[23] 9 Tr 3662.

[24] 9 Tr 3682-3703.

[25] 9 Tr 3703-07.

[26] 9 Tr 3705.

[27] 9 Tr 3707-17.

1. Expanding LIA to Automatically Enroll Food Stamp Recipients
2. Expanding LIA Credits to $60 per Month
3. Instituting an Explained LIA Credit for Customers Living Below 50% of the Federal Poverty Level
4. Restructuring and Redirecting RIA Credits to Low-Income Customers Marginally Exceeding Income Eligibility

1. Expanding LIA to Automatically Enroll Food Stamp Recipients

The AG's first recommendation is to expand LIA to automatically enroll food stamp recipients. While Mr. Colton was unable to identify exactly how many food stamps households exist in the DTE Service Territory because food stamp data is not reported on a geographic basis that would allow a precise match to the DTE territory, it is still possible to gain some insights by reviewing Food Stamp participation data on a county-specific basis and then matching those counties to the counties served by DTE Electric.[28] Mr. Colton notes that food stamp participants in DTE's electric service territories have average incomes that would indicate that their home electric burdens would be high.[29] No average food stamp income in the DTE service territory would result in an affordable electric bill to food stamp recipients.

The automatic enrollment portion is as follows:

DTE's LIA tariff already provides that a DTE customer who can show that he or she is also a Food Stamp recipient will be qualified to receive the LIA credits. A customer, however, has to apply for the LIA and be found to be a Food Stamp participant. I propose that DTE instead engage in an annual data exchange with

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[28] 9 Tr 3717-18.

[29] 9 Tr 3718-19.

Michigan's Food Stamp office to determine those DTE customers who receive Food Stamps. The Food Stamp program in Michigan is administered by the State Department of Health and Human Services (DHHS), the same state department that administers the State Emergency Relief program. In the telephone industry, the electronic exchange of data for purposes of establishing Telephone Lifeline eligibility has long been held to be permissible for purposes of automatic enrollment as a "routine use" under federal privacy statutes. Reducing this barrier to accessing some utility bill relief could be very helpful to DTE customers.

2. Expanding LIA Credits to $60 per Month

DTE concedes that while both the RIA and LIA "are credits, they are not a comprehensive program like LSP. The credits also serve to supplement the LSP program."[30] The AG's second recommendation is that the LIA credit in particular should be expanded from $40/month to $60/month in order to provide meaningful affordability relief to recipients of the credit. The purpose of a low-income discount is to improve the affordability of utility service to income-eligible customers who would face unaffordable bills in the absence of the discount. In noting that "affordability" is the objective, it is important to remember that pursuing affordability, and thus offering a low-income discount, is a means to an end, not an end unto itself. The outcome which stakeholders seek to achieve through a more

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[30] Ex. MEC-12 (MECNRDCSCDE-6.4(f)).

affordable utility rate is the ability of income-challenged customers to take utility service under sustainable conditions.[31]

The impact of expanding the LIA credit from $40 to $60 per month would be to reduce electric burdens for households at 150% of the federal poverty level (FPL) to between 4.7% and 7.7% throughout DTE Electric's territory. Expanding the LIA credit from $40 to $60 per month would result in a range of electric burdens for households at 100% of FPL going from a low of 7.0% to a high of 11.6%. While these burdens are still unaffordable, they are not unreasonable outcomes given use of the blunt instrument of equal monthly bill credits across income and usage levels.[32]

3. Instituting an Explained LIA Credit for Customers Living Below 50% of the Federal Poverty Level

The AG's third recommended modification of DTE's LIA program is that customers who demonstrate that they participate in certain programs that would indicate that they fall in the extremes of low Poverty Levels be given a special additional adder to the LIA benefits that they receive from DTE. Specifically, the AG recommends that these customers be provided an additional benefit of $25 per month above and beyond those LIA benefits provided to all LIA recipients. This additional benefit would provide a total benefit to these customers in extreme poverty of $85 per month.[33]

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[31] 9 Tr 3720.

[32] 9 Tr 3724.

[33] 9 Tr 3724.

At the existing level of LIA credits, for customers with income at or below 50% of Federal Poverty Level, 297 of the 347 jurisdictions served by DTE electric have electric burdens for customers of 20% or more. If one uses the LIA credit proposed in Mr. Colton's testimony, the affordability improves, but is still unreasonably high. For customers with income at or below 50% of FPL, even the expanded LIA credit proposed in Mr. Colton's testimony results in 250 of the 347 jurisdictions having electric burdens of 18% of income or more.[34]

It would be unreasonable to expand the LIA credit even more for all LIA recipients. Customers with incomes at 150% of FPL do not need a further expanded LIA in order to reach or approach some semblance of an affordable burden. The problem of continuing unaffordability even at a $60 LIA credit is most palpable for customers living in extreme Poverty (i.e., below 50% of FPL). Accordingly, the AG proposes a special adder to the LIA credit to customers who can show their participation in a public assistance program that is nearly certain to indicate that the household lives in extreme Poverty. The adder would be an additional $25 per month above the LIA proposed in this proceeding for all LIA customers, for a total of $85.[35]

These additional benefits are ones that Mr. Colton has proposed, and seen success with, in other states.[36]

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[34] 9 Tr 3725.

[35] 9 Tr 3725-26.

[36] 9 Tr 3726-27.

4. **Restructuring and Redirecting RIA Credits to Low-Income Customers Marginally Exceeding Income Eligibility**

Existing DTE programs are directed toward households with income at or below 150% of the FPL. However, the incomes needed for customers to be "self-sufficient" are considerably higher than 150% of FPL.[37] As established in Part 1 of Mr. Colton's testimony, self-sufficiency incomes in Michigan can be at 250% of FPL, and at times even higher. Customers with these higher incomes, however, are not likely to be recipients of public assistance. Accordingly, the AG recommends that the RIA program be restructured to provide assistance to customers establishing special needs when those customers have documented income not exceeding 200% of the FPL. Rather than funding these redirected benefits through new costs to ratepayers, this restructured program should be funded through dollars that are already planned to be directed to RIA recipients with income at or below 150% of FPL.

The rationale for providing the RIA credit to customers in special need with annual income between 150% and 200% of poverty level is relatively straightforward. While customers at 150% of FPL had improved affordability relative to even lower income customers (i.e., those at 100% of FPL, those at 50% of FPL), a substantial number of DTE jurisdictions still fell substantially above the definition of an affordable bill.[38]

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[37] 9 Tr 3728.

[38] See, e.g. Roger Colton Direct Testimony Table 2, 9 Tr 3652.

When using the actual bill level experienced by LIA customers, which is substantially higher than the average residential bill, Mr. Colton's Table 25[39] demonstrates that the existing LIA credit still results in significant unaffordability for households at 150% of FPL. Even after subtracting the LIA credit, 344 of DTE's 347 electric jurisdictions have bill burdens at or above two times higher than the affordable burden for households at 150% of FPL. Given this impact at the maximum income eligibility, it is reasonable to conclude that there will be declining, but nonetheless substantial, bill unaffordability problems for households with incomes marginally exceeding this maximum allowable income.[40]

Ultimately, the AG recommends that the RIA credit be set equal to the DTE electric customer charge. To the extent that the customer charge remains the same in this or future cases, the RIA credit would remain constant as well, at $7.50 per month. To the extent that the customer charge is increased, however, the RIA credit would be indexed to track those future changes.

For customers to actually access the RIA credit, the AG recommends that DTE's outreach and intake procedures remain as they are. To the extent that a public assistance program would demonstrate an income-eligibility for the RIA, proof of participation in that assistance program should be accepted as proof of eligibility for the RIA. To the extent that a household does not participate in such a public assistance program, just as DTE does not, the Company should accept

[39] 9 Tr 3725.

[40] 9 Tr 3729-30.

documentation from one of its community-based intake organizations that the customer is income-eligible. It should not be difficult for DTE to identify customers with income up to 200% of FPL. DTE Electric's seasonal protections extend up to 200% of FPL.[41] DTE Electric has established procedures for identifying households with income up to 200% of FPL.[42] A household that has been so identified appears in the customer profile of the DTE Electric Customer Relational Management program.[43] A customer who has been qualified for the seasonal protections should be found to have established "special needs" for purposes of the redirected RIA credits.

Conclusion

The AG recommends that the Commission adopt her recommendations as laid out above and as detailed in Mr. Colton's testimony.

Sebastian Coppola

Attorney General witness Sebastian Coppola took an in-depth look at DTE's entire filing and provided testimony with regard to much of the Company's request. He determined that DTE has a revenue deficiency of no more than $41.1 million and that the ROE be set at 9.25%, both of which the AG recommends that the Commission now adopt.

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[41] Exhibit MEC-30 (MECNRDCSCDE-6.9(a)).

[42] Exhibit MEC-30 (MECNRDCSCDE-6.9(b)).

[43] Exhibit MEC-30 (MECNRDCSCDE-6.9(c)).

Projected Test Year

As a preliminary matter, the AG provides some thoughts and recommendations with regard to DTE's use of a projected test year in these rate cases.

The Attorney General supports ABATE's proposal,[44] sponsored by ABATE's witness James R. Dauphinais, for the Commission to initiate a generic proceeding to review the experience to date with the use of a projected test year by Michigan utilities. The Attorney General also supports Mr. Dauphinais' testimony that the Commission is not required to set rates using a projected test year. As noted in his testimony, MCL 460.6a provides that "a utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges," but it does not require the Commission to use them in reviewing the company's rate increase request. This provision simply allows the company the opportunity to present a rate increase using projected costs and revenues, but it does not tie the hands of the Commission as to how to review and ultimately determine the revenue deficiency or sufficiency of the company. As stated by the Michigan Court of Appeals, because MCL 460.6a mentions only that the utility may use projected costs and revenues, it conversely is not a mandate on the Commission to adopt it.[45]

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[44] 7 Tr 1642-50.

[45] *Detroit Edison Company v Celadon Trucking Company,* 248 Mich App 118 (2001) (stating that "[T]he express mention of one thing in a statute implies the exclusion of other similar things.").

The Attorney General agrees with ABATE's findings that DTE Electric and other utilities have disproportionally benefited from use of the projected test year, as demonstrated by excessive level of earnings above the authorized ROE and high revenue sufficiency amounts in the historical periods.[46] For example, as shown in Table JRD-2 of Mr. Dauphinais' direct testimony, in three of the last four rate cases, DTE Electric has filed a new rate case when in the historical year the company had a revenue sufficiency ranging from approximately $18 million to $111 million.[47] Additionally, as shown in Table JRD-3 of Mr. Dauphinais' direct testimony, over the five-year period from 2014 to 2018, DTE Electric has over-earned in excess of $117 million in revenue through the use of the projected test year.[48]

Moreover, the Attorney General seeks to draw the Commission's attention to the length of forecasted time period incorporated in recent rate case filings. As demonstrated in this case, the projected test year usually begins several months after the end of the historical test year, which creates an additional period of projected data and revenue requirement. For example, in the instant case, DTE Electric historical test year ended December 31, 2018, and the Company proposed a future test year beginning on May 1, 2020 and ending April 30, 2021. As a result of the extended forecasted test year, the Company also forecasted capital expenditures for the period from January 1, 2019 to April 30, 2020. Therefore, in total the rate

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[46] 7 Tr 1642-50.

[47] 7 Tr 1642.

[48] 7 Tr 1646.

case required 28 months of projected capital expenditures from January 1, 2019 to April 2021. The problem with long forecasted period is not limited to capital expenditures. It is also more difficult and less accurate to project revenues and operations and maintenance expenses that will occur nearly two years down the road. Mr. Dauphinais' direct testimony discusses some of the inaccuracies and problems resulting from such long forecasts.

Accordingly, the AG recommends that the Commission initiate a generic proceeding with a review that includes consideration of both the benefits and detriments to customers from the use of a projected test year. The review should also examine issues, such as:

1. The conditions under which the Commission would reject the use of a projected test year;

2. The types of projected costs and investments that should be excluded from a projected test year;

3. The minimum criteria that needs to be met to reasonably demonstrate that the utility will actually incur the projected expense or investment;

4. The length of time allowed between the end of the utility's historical test year and the beginning of the utility's proposed projected test year with the objective of shortening this "bridge period" to less than six months; and

5. How the use of a projected test year reduces regulatory risk and should be included as a factor in determining the authorized return on equity of a utility.

I. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

Mr. Coppola's analysis begins with a discussion of the level of capital expenditures proposed by DTE in this case and the resulting increase in rate base. This is an area of escalating concern for the AG.

> In this general rate case, DTEE has proposed capital expenditures of $2.1 billion for 2019, $765.4 million of the 4 months ending April 2020 ($2.3 billion annualized), and an additional $1.8 billion for the 12 months ending April 2021. The total proposed capital expenditures over this 28-month period are nearly $4.6 billion. These expenditures follow capital expenditures of $3.1 billion made during the prior two years in 2017 and 2018.[49]

Based on Table 1 in Mr. Coppola's testimony, it can be seen that, up until 2011 DTE was able to keep capital expenditures below $1 billion annually. Now, only ten years later, the level of capital expenditures has more than doubled.

DTE's capital expenditures have in turn fueled a tremendous increase in rate base. The Company's proposal in this case would increase rate base by 12%, to $18.3 billion, which is more than double the amount of DTE's rate base 12 year ago. Simply put, this unbridled growth in rate base has, and will continue to have, significant negative implications for customer bills as DTE seeks ever-larger rate increases.

As Mr. Coppola discusses in his testimony,[50] there appear to be two main drivers behind the increase in rate base. First, there is some necessary replacement of aging infrastructure and new capital spending to address market growth that have required an increase in capital expenditures. While some of the work is necessary and certainly should be performed, DTE's recent requests have included hundreds of millions of dollars in expensive projects such as IT upgrades, headquarter and control center upgrades, employee compensation and benefits

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[49] 9 Tr 2965, citing to Exhibit A-12, Schedule B5 in Case No. U-20162 and Case No. U-20561.

[50] 9 Tr 2967-68.

expansion etc., that are unrelated or only tangentially related to fundamental infrastructure upgrades and serve mainly to increase rate base and customer costs without providing commensurate customer value.

The second, and arguably bigger, driver behind the increase in rate base is that it has given DTE the opportunity to increase earnings growth. For utility companies, earnings growth is directly related to rate base growth, dividend growth, and stock price appreciation for shareholders. Exhibit AG-1.1 includes pertinent pages from an October 2, 2019 Investor Presentation, which show this drive to increase earnings through increased capital spending at the utility.

It is important to keep this tremendous increase in rate base in mind when considering DTE's requests in the rest of this case, how approving those requests will affect DTE's customers, and the validity/necessity of the different requests. If DTE continues its current practice of annual rate cases and rate increase requests in the hundreds of millions of dollars, in 10 years the average residential total annual electric bill will nearly triple, from $1,192 in 2019 to $3,076 in 2030.[51] To avoid even greater bill affordability problems than what exist today, as described in Mr. Colton's testimony, DTE needs to moderate and be more selective in its capital spending in coming years.

[51] 9 Tr 2968-69.

II. SALES REVENUE ADJUSTMENT

Through the direct testimony of Company witness Markus Leuker, the Company is forecasting total electricity sales of 46,007 Gigawatt hours (GWh) for the May 2020 to April 2021 test year. This represents an overall decrease of 673 GWh, or 1.4%, in comparison to the weather-normalized actual sales of 46,680 GWh in 2018.[52] From reviewing Mr. Leuker's testimony and exhibits, as well as responses to data requests, it appears that most of the decline is attributed to (1) the decline in residential and commercial sales, primarily from forecasted energy efficiency, and (2) the decline in industrial sales.

The AG argues that DTE's forecasts for residential, commercial, and industrial sales are significantly understated. Exhibit AG-1.25 presents analysis of historical temperature-normalized residential and C&I sales for the five years, 2014-2018, which is then compared to the forecasted sales for 2019, 2020, and the projected test year. Mr. Coppola's testimony provides further analysis and calculations for sales per residential and C&I customers and why DTE's assumptions and projections are understated.[53]

Exhibits AG-1.27, AG-1.28, and AG-1.29 present an alternative, more realistic calculation of residential and commercial sales and the related revenue for the projected test year.[54] Based on that analysis, the combined incremental revenue

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[52] Exhibit A-5, Schedule E1, page 4, for 2018, and Exhibit A-15 Schedule E1, page 1, for the projected test period.

[53] 9 Tr 3038-42.

[54] 9 Tr 3042-43.

for the Company for residential and commercial sales would be $12,166,353. Accordingly, the AG recommends that the Commission adopt the AG's residential and commercial sales forecast and reflect the additional revenue Mr. Coppola calculated in determining an appropriate revenue deficiency for the Company for the projected test year. Exhibit AG-1.29 shows the sales billing determinants reflective of the sales adjustments.

In rebuttal, Company witness Markus Leuker argues that Mr. Coppola's sales adjustments are not appropriate.[55] On page 2 of his rebuttal, Mr. Leuker argues that Mr. Coppola's method of forecasting sales is simplistic and flawed because Mr. Coppola used a 4-year average historical usage per customer to forecast sales.[56] Simply because a method is "simple" does not make it wrong or flawed, as Mr. Leuker implies in his rebuttal testimony. As noted on cross examination, Mr. Leuker used a method of forecasting, or "markets that used CAGRs [compound annual growth rates] for their forecasts," in DTE's recent IRP (U-20471), similar to what Mr. Coppola used in this case.[57] The only difference, as noted on cross, is that while Mr. Coppola used his method to forecast sales for the future test year, which is about two years ahead, Mr. Leuker used the method to calculate future sales in the IRP for a longer period of time, ten years or more.[58] It is disingenuous for DTE

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[55] 4 Tr 424.

[56] 4 Tr 424.

[57] 4 Tr 433.

[58] 4 Tr 433.

to argue that the AG's forecasting methods are simplistic and flawed when the Company itself relies on those very same methods in other cases.

In rebuttal Mr. Leuker also contends that Mr. Coppola did not adequately consider the amount of lost sales from DTE's EWR program.[59] However, on cross Mr. Leuker agreed that the historical weather-normalized sales used by Mr. Coppola include losses from the EWR program actually experienced during the four-year period.[60] This is important because it means that Mr. Coppola used actual results that show the actual level of losses experienced. Also in rebuttal and on cross, Mr. Leuker argued that, because DTE adjusted the targeted level of EWR savings for the rate case test period upward to 1.75%,[61] Mr. Coppola's analysis failed to capture the "negative impact on sales" that would have.[62]

However, the problem with Mr. Leuker's argument here is that the fact that the Company may "target" a certain percentage of energy efficiency through the EWR program does not necessarily mean that the same percentage will actually be experienced or achieved by customers. On cross, Mr. Leuker wanted to discuss targets that DTE's EWR team "has to achieve" and the fact that the team has consistently "met or exceeded its target."[63] When asked if that meant that

[59] 4 Tr 433.

[60] 4 Tr 433-34.

[61] 4 Tr 434.

[62] 4 Tr 434.

[63] 4 Tr 435.

customers are actually carrying out the energy efficiency measures, Mr. Leuker responded

> The EWR team, the method of measuring what the EWR targeted savings is, is a calculated MEMD database that the team uses to validate the savings. So for instance, if you, if DTE incentivized a light bulb, there is a particular savings associated with that light bulb. That is calculated in the data base, and the programs that we use and that we incentivize for energy efficiency are then calculated against that database and the savings is achieved. And that is the reported savings that the Company is held accountable to.[64]

That is a vague and confusing answer that appears to roughly describe what DTE's "EWR team" does and what its responsibilities are. What is clear is that, as Mr. Leuker then later admitted on cross, the EWR "calculations" that are made by DTE and included in this case as "losses" contain assumptions and DTE is unable to determine whether or not customers actually undertake the energy efficiency initiatives that the EWR team is "calculating."[65] As stated later during cross, there is a difference in what DTE sees in total, actual sales decline versus EWR.[66] Accordingly, it is more appropriate to use Mr. Coppola's analysis, which is based on actual numbers that contain actual EWR savings, rather than DTE's projections based on unverifiable numbers.

Additionally, Exhibit AG-1.25 shows an analysis that Mr. Coppola performed of sales trends over the four-year period. It shows that the actual decline in sales is less than the 1.15% to 1.5% that the Company has targeted in EWR sales losses

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[64] 4 Tr 435-36.

[65] 4 Tr 436.

[66] 4 Tr 439.

from 2014 to 2018. This means either that some other factors are offsetting the EWR losses, or that the losses are not being recognized to the level DTE has targeted. So, when Mr. Coppola used the 0.91% rate of decline in sales for residential customers and the 0.71% rate of decline for commercial and industrial customers, he has included all those other factors in his forecast.

On page 3 of Mr. Leuker's rebuttal, lines 12-14, he states that residential sales for the future test year are forecasted to decline 446 gigawatt hours (GWh) from 2019, due to EWR losses and customer-owned generation.[67] In response to discovery, Mr. Leuker stated that of the 446 GWh of lower residential sales, 418.6 GWh pertain to EWR losses and 27.7 GWh pertain to customer-owned generation.[68] He also stated that in calculating the EWR losses from 2009 to the end of the future test year he used the difference of 0.25% between the current 1.5% target rate and the 1.75% future target rate.[69]

Line 7, column (i) of Exhibit AG-1.25 shows DTE's forecasted residential sales for 2019. If the .0025 factor from above (0.25%) is applied to the 14,934 gigawatts of sales in 2019, the total for 2020 is 37.3 GWh.[70] Even if that number is doubled to include 2018 and part of 2021, that gives a number that is far removed from the 418.6 GWh calculated by Mr. Leuker. Based on this it appears that Mr. Leuker's model and calculations are incorrect and significantly overstate the

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[67] 4 Tr 436.

[68] AGDE-6.209a, Ex. AG-1.44.

[69] AGDE-6.209b, Ex. AG-1.44.

[70] 14934*.0025 = 37.3.

incremental losses over what Mr. Coppola has forecasted. As noted, Mr. Coppola's sales forecast for the future test year already includes the base amount of EWR losses included in the historical period. So, at most any sales reductions from Mr. Coppola's model should be the difference between 1.75% and 1.50%, or a factor of 0.0025.

With regard to customer-owned generation, Mr. Leuker assumed an increased loss of 27.7 GWh.[71] As shown in DR AGDE-6.208[72] that represents only 0.19% of total residential sales, which is a very small amount. In direct testimony, Mr. Coppola questioned DTE's assumptions about the growth rates used in calculating these sales losses from customer owned generation and the accuracy of those calculated losses.[73] Mr. Leuker did not respond to that testimony in his rebuttal and similar to Mr. Leuker's rebuttal on EWR losses, it is likely that the 27.7 GWh in sales losses are overstated.

Also in rebuttal, on page 4, Mr. Leuker criticizes Mr. Coppola's use of different historical periods in his evaluation of the calculation of sales forecasts in prior rate cases.[74] In discovery, the AG requested data from the Company on the period of historical customer data DTE has used in forecasting sales in prior rate cases and PSCR cases.[75] The Company responded that the data was not available

[71] AGDE-6.209b, Ex. AG-1.44.

[72] Ex. AG-1.44.

[73] Direct Testimony of Sebastian Coppola pp 87-88.

[74] 4 Tr 441.

[75] Ex. AG-1.45.

in the format requested.[76] On cross, Mr. Leuker stated that this was because DTE breaks this data into individual markets, so the data requested by the AG at a "class level" was not readily available.[77] However, none of this was expressed to the AG in the discovery responses[78] and DTE instead provided an evasive answer. When pressed on cross, Mr. Leuker agreed that it is possible that DTE used historical customer data of varying time periods in prior cases, because "timeframes change all the time."[79] Based on DTE's unwillingness to answer the discovery or undertake any analysis to provide an answer to the discovery, it appears that the Company did not want to disclose its use of historical customer data of varying time periods because it would contradict Mr. Leuker's rebuttal testimony and his criticism of Mr. Coppola. The AG argues that using data from different historical periods does not necessarily make the forecast wrong or any less reliable.

Finally, on page 6 of Mr. Leuker's rebuttal he presents the results of his calculations using Mr. Coppola's model with customer usage data updated for 2019.[80] As confirmed on cross, Mr. Leuker's 2019 sales numbers still include two months of forecasted sales based on his model, so it is not 12 months of actual customer sales.[81] From Mr. Leuker's rebuttal on page 6, lines 6-17, it can be seen

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[76] Ex. AG-1.45.

[77] 4 Tr 442-43.

[78] 4 Tr 443.

[79] 4 Tr 444.

[80] 4 Tr 444.

[81] 4 Tr 444-45.

that he extrapolated the usage per customer numbers for the projected test year in a different way than Mr. Coppola calculated in Exhibits AG-1.27 and AG-1.28. Therefore, it is not surprising that Mr. Leuker's "revised" results match closely to what he had originally forecasted.

Accordingly, the AG continues to recommend that the Commission adopt the AG's residential and commercial sales forecast and reflect the additional revenue Mr. Coppola calculated in determining an appropriate revenue deficiency for the Company for the projected test year. Exhibit AG-1.29 shows the sales billing determinants reflective of the sales adjustments.

III. OPERATIONS AND MAINTENANCE EXPENSES

In his direct testimony, Mr. Coppola, addresses a number of Operations and Maintenance (O&M) Expense reduction recommendations.[82] DTE has projected an O&M expense increase in this case of $84.3 million, or 7%, over the historical level.[83]

A. Inflation Adjustment

Approximately $69.8 million of the projected O&M increase represents inflation increases estimated by DTE based on a blend of (a) the Consumer Price Index-Urban index ("CPI" or "CPI-Urban") and (b) 3% forecasted annual wage rate inflation for union, non-union, and contract employees of the Company.[84] The use of

[82] 9 TR 3044-74

[83] 9 Tr 3044.

[84] 9 Tr 3044.

such a 'blended rate' has been rejected by the Commission in prior general rate cases as inappropriate. In Case No. U-18014, the ALJ and the Commission directly rejected DTE Electric's proposed blended inflation rate.[85] In U-18014, the Commission agreed with the ALJ's statement that the Commission has never approved a composite rate derived from internal and public sources and concluded that "the Commission has never found sufficient justification or support to approve a composite labor/non-labor inflation rate."[86] In MPSC Case No. U-18255, the Commission reinforced its past findings and conclusions, stating that, "[t]he Commission agrees with the ALJ that DTE Electric has not presented sufficient evidence in this case to induce the Commission to depart from its decisions in the 2017 order and previous rate cases rejecting a blended inflation rate."[87] The Commission reiterated its position in DTE's last rate case, U-20162.[88]

Not only did the Commission explicitly reject this blended rate of inflation in DTE's last three electric rate cases, the evidence in this case demonstrates that DTE has not experienced across-the-board inflation pressure on its operating costs.[89] According to DTE's own testimony, actual O&M costs have remained well

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[85] *In the matter of the Application of DTE Electric Company*, MPSC Case No. U-18014, January 31, 2017 Commission Order, pp 71-72.

[86] Id. p 72.

[87] *In the matter of the Application of DTE Electric Company*, MPSC Case No. U-18255, April 18, 2018 Commission Order, p 38.

[88] *In the matter of the Application of DTE Electric Company*, MPSC Case No. U-20162, May 2, 2019 Commission Order, p 74.

[89] 9 Tr 3044.

below the inflation trend line from 2009 to 2018.[90] Based on that, the AG finds it difficult to understand why DTE would project inflation-related cost increases for 2019, 2020, and the four months in 2021.

The Company has also been very vocal in stating that investments in technology will result in the reduction of O&M expenses. Yet, customers now must pay higher rates due to forecasted increases in O&M costs. The Company has not provided any evidence that its operations are facing inflationary cost pressures that it cannot manage in the course of operating its business. It is more than likely, based on historical data, that the proposed $69.8 million in inflation cost increases will not happen. The Company will likely continue to manage its operations to offset the low level of forecasted inflation with increased operating efficiencies and cost cutting. It is disingenuous for the Company to continue predicting inflation-related increases in each subsequent rate case, when the trends and numbers clearly do not bear that out.

As Mr. Coppola highlighted in his testimony,

> As a matter of policy, it is not advisable to allow utilities to escalate costs for forecasted future inflation. It becomes a self-fulfilling prophecy to increase future costs with inflation increases which then fuel and justify further inflationary trends. The Commission should only grant inflation cost increases when those increases are actually experienced and are likely to occur, and not because it has been past practice to do so. In this case, the evidence is clear that inflation cost increases are not warranted or necessary.[91]

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[90] Revised Direct Testimony of Michael Cooper, p 52.

[91] 9 Tr 3045-46.

Throughout Mr. Coppola's testimony on O&M expenses he demonstrates that 2019 O&M expenses were well below projected levels and below proposed inflation cost adjustments. As such, it is reasonable to conclude that inflation is not impacting the O&M expenses of the Company, and no such adjustments should be approved by the Commission.

In this case, the evidence is clear that inflation cost increases are not warranted or necessary. The Company has not provided any evidence that its operations are facing inflationary cost pressures that it cannot manage in the course of operating its business. Therefore, the proposed $69.8 million in inflation cost increases is not likely to occur in the coming months as the Company has predicted and should be disallowed by the Commission.

Alternative Inflation Adjustment

As discussed above, the Commission has repeatedly rejected DTE's request to use a blended inflation rate in these cases. *If* the Commission determines to allow any level of future inflationary cost adjustment it should not accept DTE's proposed blended inflation rates.[92] In prior cases, the Commission has been persuaded to grant some level of inflationary cost increases equal to the CPI-Urban index. In this regard, if the Commission decides to again use the CPI-Urban index, it should use the most recent information available. The CPI-Urban index inflation rates proposed by the Company are now stale. Exhibit AG-1.30 includes a copy of the

[92] 9 Tr 3046-47.

CPI-Urban index inflation rates from IHS Markit for 2019, 2020 and 2021. These rates are 1.9% for 2019, 2.1% for 2020 and 1.8% for 2021.

B. Distribution O&M Expenses

In his direct testimony, Mr. Coppola provides a summary of the Company's projected Distribution O&M expenses in its test year:

> As shown in Exhibit A-13, Schedules C5.6, the Company is proposing $336.5 million of O&M expense for the projected test year for its Distribution operations. The Company's adjusted O&M expenses for these operations in 2018 was $313.2 million. To this cost level, the Company added $21.3 million in projected inflation adjustments and also applied additional cost adjustments of $2.0 million for other items. The net result is a spending level of $336.5 million.[93]

In his direct testimony Mr. Coppola details numerous adjustments to DTE's proposed O&M expense for distribution operations that he recommends, specifically for 1) actual 2019 expenses that were far below the Company's forecasted amount, 2) retroactive inflation cost increases, and 3) higher tree trimming expenses.[94] The AG adopts those and accordingly recommends, as per the prior discussion, that the Commission disallow all $21.3 million in projected inflation cost increases in this area. The AG also recommends that the Commission reduce DTE's forecasted O&M expenses by $5.1 million for actual O&M expenses for distribution operations,[95] and

[93] 9 Tr 3048.

[94] 9 Tr 3048-52.

[95] Ex. AG-1.32.

disallow DTE's requested higher tree trimming expense of $2.8 million for the projected test year.[96]

With regard to the Company's proposed extension of its tree-trimming surge program, the AG recommends that the Commission deny the request, as there is no need to expand the program further at this point. The Commission approved a three-year period of funding for this costly program in order to ascertain if the surge program was achieving the claimed benefits, before approving a longer-term program. Nothing of significance has changed since the Commission decision in May 2019 that justifies extending approval for another year through the year 2022.

The main reason that Ms. Rivard offers in her direct testimony for an extension of the program is that tree trimming contractors may go to other states if there is no assurance that the DTEE tree trimming surge program will continue through 2022. This claim is perplexing, because in response to discovery DTEE disclosed that the current contracts with tree trimming contractors expire on January 1, 2020 and the Company is currently negotiating new three-year contracts with contractors that will begin in January 2020. These contracts would span through January 2023.[97] The new contracts should remove any concerns about not having contractors for the year 2022. Furthermore, if the Company strongly believes that over the coming three years the surge program has achieved the benefits claimed in Case No. U-20162, it can proceed with the required amount of

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[96] 9 Tr 3051.

[97] 9 Tr 3052.

surge spending for 2022. The Company can later request inclusion of those costs in the regulatory asset for future recovery in a subsequent rate case. If the Company is able to make a convincing case before the Commission that the costs were reasonable, prudent, and achieved the desired outcome, it should be able to recover those costs. At this time, there is not sufficient evidence to assess the merits of a program that was approved only a few months ago.

In rebuttal testimony, Company witness Ms. Rivard disagrees with Mr. Coppola's proposal that the Commission should approve the same expense amount for tree trimming expenses for the future test year as was approved in U-20162.[98] In U-20162 the Commission approved $95.1 million for the year ending April 30, 2020 and in this rate case Ms. Rivard wants to increase that by another $2.8 million for the projected test year ending April 2021 based on a projected inflation rate of 2.9%, as provided by witness Uzenski.[99] So, before DTE has even spent the $95.1 million for the year ending April 2020, Mr. Rivard is already proposing to increase that amount by a projected inflation rate.

As was discussed, the 2.9% inflation proposal represents a blended rate of inflation consisting of the CPI-Urban forecast and the Company's internal wage inflation forecast, an approach which has been repeatedly rejected by the Commission. Also in her rebuttal testimony Ms. Rivard quotes her testimony in U-20162, where she used a 3% rate of inflation to forecast future tree trimming

[98] 9 Tr 3631.

[99] 9 Tr 3632; Ex. A-13, Schedule C5.15.

expenses.[100] The issue is that that 3% rate was used to provide the long-term cost forecast of the tree trimming surge program through 2025 and in its order in U-20162 the Commission did not adopt a 3% rate of inflation to set the base level of tree trimming expense for future years.

Also in U-20162 the Commission set specific additional surge expense amounts for tree trimming of $43.3 million for 2019, $74.1 million for 2020, and $70.5 million for 2021.[101] The Commission did not state in the order that those amounts or the base amount of $95.1 million should be adjusted for inflation in future years. The AG continues to recommend that the Commission disallow recovery of any additional amount for tree trimming.

On page 4 of her rebuttal, Ms. Rivard disagrees with Mr. Coppola's recommendation that the Commission deny DTE's proposal to approve another year of the surge program.[102] So, with the first year of the three-year surge program not even completed, Ms. Rivard proposes to extend the program an additional year to 2022. The only rationale provided by Ms. Rivard is that DTE needs to commit work to tree trimmers at least two to three years before 2022.[103] It is unclear how long of a commitment DTE has given to tree trimming contractors in the past, and also unclear why DTE should need Commission approval to inform tree-trimming

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[100] 9 Tr 3631-32.

[101] U-20162 Commission Order, p 80.

[102] 9 Tr 3633.

[103] 9 Tr 3633.

contractors about 2022 work if it is so confident that the surge program is working well and will be effective in reducing future power outages.

The AG continues to argue that a fourth year should not be added until sufficient evidence is presented to show that the first three years of the surge program have significantly reduced power outages, such that the surge spending is justified. Therefore, the AG continues to recommend that the Commission deny the requested extension of funding for the surge program through 2022.

C. Steam, Hydraulic & Other Power Generation

In his direct testimony, Mr. Coppola gives an overview of DTE's proposed O&M expenses for its steam, hydraulic, and other power generation options.[104] The Company's overall proposal is a spending level of $304.8 million.[105] Exhibit AG-1.33 contains O&M expense levels for these specific operations, over the 2014-2019 time period. The exhibit shows a 13.6% decline in O&M expense from 2014 to 2019 on an annualized basis. This declining trend reflects the reduction in operating costs from retirement of some coal plants and achieved operating efficiencies. The trend is likely to continue into future years as the Company continues to retire additional coal-burning power plants.

Based on all of the information that was made available to the AG, DTE's 2019 year to date spending through September 2019 was 11% below the 2018

[104] 9 Tr 3053-54.

[105] 9 Tr 3053.

level.[106] To adopt the Company's proposed $304.8 million test year O&M expense level for these operations, including $20.3 million of inflation, would put the spending level at $39 million above what is being experienced in 2019, which would be approximately double the level of the inflation adjustment recommended by the Company. It is clear that the Company's proposed inflation adjustments for these operations are unsupported by the evidence. As such, they are unwarranted and would unreasonably increase costs for customers through higher rates if included in the determination of the Company's revenue requirement. Therefore, the AG recommends that the Commission disallow the $20.3 million of inflation proposed by the Company for these three operations and all other inflation adjustments proposed by the Company in this rate case.

The AG also proposes a $3.1 million adjustment to Steam Generation O&M expense for the projected test year pertaining to the retirement of the St. Clair Unit #1 in March 2019. In Exhibit A-13, Schedule C5.1, the Company has included the removal of $1.4 million of expense to reflect the lower future operation and maintenance expenses after the retirement of this power generating unit. However, the adjustment proposed by the Company is not sufficient. According to the AG's calculations, the adjustment to future O&M expense should be $4.5 million.[107] The

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[106] 9 Tr 3054.

[107] 9 Tr 3055.

calculation of the $4.5 million is discussed at pages 103 and 104 of Mr. Coppola's direct testimony, and included in Exhibits AG-1.35 and AG-1.36.[108]

D. Merchant (Credit/Debit Card) Fees

On page 1 of Exhibit A-13, Schedule C5.7.1, the Company shows a dramatic increase in Debit and Credit Card fees from $10.5 million in 2018 to a projected amount of $19.1 million for the test year. This is nearly a doubling of the expense amount in about two-and-half years. The projected increase is more dramatic for non-residential customers, where merchant fees are increasing from $4.7 million in 2018 to $10.7 million in the projected test year. The popularity of this program has grown as the Company has advertised this cost-free option to its customers.

To get these costs under control, Company witness Eric Clinton proposed to limit eligibility for cost-free Debit/Credit card payments for non-residential customers to those customers that have less than $75,000 in annual bills. According to the Company, this restriction would reduce the amount of fees for non-residential customers by $4.7 million. However, the Company did not include the $4.7 million cost savings of limiting eligibility for non-residential customers in its projected O&M expense for merchant fees. The AG now recommends that DTE accept this restriction and remove $4.7 million of merchant fees from the projected test O&M expense.

[108] 9 Tr 3054-57.

In rebuttal, Company witness Eric Clinton disagreed with Mr. Coppola's characterization that DTE has advertised the use of credit cards as a cost-free option to pay electric bills.[109] However, when shown Ex. AG-1.49 during cross-examination, he agreed that it contained DTE communications to customers that reference the "fee-free" option of paying by credit card.[110] Accordingly, the Company's own materials circulated to customers unequivocally advertises a cost-free option of paying by credit card. This promotional effort is likely driving a large portion of the increase in credit card fees paid by the Company, which Mr. Clinton proposed to recover in this case.

Also in rebuttal Mr. Clinton disagrees with the AG's proposed reduction of $4.7 million in credit card fees for the future test year, if the Commission adopts the proposal restricting customers with annual bills greater than $75,000 from using credit/debit cards.[111] His position is that the reduction should only be $2 million, because the computer changes require to implement the change in policy would not be done until January 2021.[112] Ex. AG-1.50 contains a discovery request in which the AG asked DTE to explain why it would take 7 months to implement the relevant computer changes. In the response, which is also included in Ex. AG-1.50, Mr. Clinton basically states that the reason is that it is a complex billing system

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[109] 6 Tr 1047.

[110] 6 Tr 1096.

[111] 6 Tr 1100.

[112] 6 Tr 1100.

change.[113] On cross, Mr. Clinton agreed that, to date, there has been no analysis performed by the Company's IT department as to what it would take to implement the change or how long it would take.[114]

If DTE thinks that limiting the use of credit cards to annual bills of $75,000 or less is the right thing to do, DTE could implement the change now and not wait for a Commission order. The Company could also notify customers immediately about the change and save customers even more money. The Company's arguments of complex billing system changes are also unconvincing and unsupported and should be rejected by the Commission.

Accordingly, the AG continues to recommend that the Commission adopt the AG's recommendations as laid out above and in Mr. Coppola's testimony.

E. Uncollectible Account Expense

The AG recommends a decrease in DTE's projected test year uncollectible accounts expense of $2.1 million. In response to the Commission's directive in Case No. U-20162, the Company conducted a study about the impact of debit and credit card payments on uncollectible account expense. The result of the study indicates that the use of debit/credit card payments likely reduces uncollectible account expense. On page 13 of her direct testimony, Company witness Tamara Johnson reports that the Company conducted a study of customers in final arrears during the period September 2018 to January 2019. In response to discovery, Ms. Johnson

[113] 6 Tr 1101.

[114] 6 Tr 1101.

further explained that, for the customers in final arrears with little or no credit card payment history, payments by credit card resolved $1.9 million of outstanding bills after disconnection.[115]

As detailed and calculated in Exhibit AG-1.38, annualizing the $1.9 million amount results in a $4.6 million reduction in uncollectible expense over the full twelve-month historical period. Based on the 46% increase in credit card fees for residential customers from 2018 to the projected test year in Exhibit A-13, Schedule C5.7, the $4.6 million of annualized uncollectible expense reduction will likely increase to $6.7 million. Therefore, a reduction of uncollectible accounts expense of $2.1 million should be expected for the projected test year.

In rebuttal, Company witness Ms. Johnson disagrees with Mr. Coppola's proposed reduction of uncollectible accounts expense of $2.1 million related to the increased usage of credit card payments by customers.[116] She also states that Mr. Coppola assumed customer payments by debit or credit cards is a new offering to customers.[117] However, when asked about this second statement, Ms. Johnson was unable to identify where in his testimony Mr. Coppola made that assumption.[118] Accordingly, that portion of Ms. Johnson's rebuttal should be ignored by the Commission.

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[115] Exhibit AG-1.37.

[116] 6 Tr 1164.

[117] 6 Tr 1164.

[118] 6 Tr 1165.

Also on cross-examination, Ms. Johnson stated that she was aware that Company witness Clinton has forecasted a significant increase in credit card merchant fees between 2018 and the end of the future test year.[119] That increase in fees is from $10.5 million in 2018 to $19.1 million for the future test year ending April 2021.[120] As Ms. Johnson states on page 3 of her rebuttal, Mr. Coppola only used a 46% rate of increase, which pertains only to residential customers.[121] Mr. Coppola did not include any non-residential customer credit card payments in his calculations of potential reductions in uncollectible expense so in that regard, he took a relatively conservative approach.

On the bottom of page 3 and then onto page 4 of her rebuttal, Ms. Johnson states that the percentage increase in merchant fees should not be used to estimate the potential impact to uncollectible expense.[122] Her reasoning is that the projected change in residential merchant fees is associated to the total number of customers using credit cards and not those who may be disconnected.[123] On page 2 of Ex. AG-1.37, in response to a Staff discovery request, Ms. Johnson stated that based on a 5-month study, she found that if customers who had been disconnected for non-payment of their electric bills had not used credit cards that uncollectible expense would have increased by $1.9 million. On line two of Ex. AG-1.38, Mr. Coppola

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[119] 6 Tr 1165-66.

[120] Ex. A-13, Schedule C5.7.

[121] 6 Tr 1152.

[122] 6 Tr 1152-53.

[123] 6 Tr 1152-53.

annualized that $1.9 million to $4.6 million for a full year of potential reduction in uncollectible expense. Then on line 7, Mr. Coppola applied the 46% increase in credit card payments for residential customers to estimate the DTE could potentially save $6.7 million in uncollectible expense for the future test year. It is logical to assume, as Mr. Coppola shows, that if more payments are made by credit cards, then, proportionally, the same impact on uncollectible expense that Ms. Johnson calculated in her study will hold.

To get to the $2.1 million in lower uncollectible expense for the future test year, Mr. Coppola subtracted the annualized amount of $4.6 million on line 2, in Ex. AG-1.38, from the projected amount of $6.7 million on line 6. Therefore, Mr. Coppola's calculation of the reduction in uncollectible expense addresses only the increase in credit card payments, and not the entire population of customer who pay their bill by credit card.

Accordingly, the AG recommends that the Commission reduce the uncollectible accounts expense for the projected test year by $2.1 million.

F. Fixed Bill Pilot Program

The Attorney General recommends that DTE's request to conduct a fixed bill pilot program and its related expenditures be denied.[124] This is basically the same pilot program DTE proposed in its previous rate case, U-20162, which the Commission rejected. The facts and circumstances presented and argued in Case

[124] Direct Testimony of Eric Clinton, p 13.

No. U-20162 have not changed significantly. In this rate case, the Company has filed testimony and information about similar pilots and programs in other states, but the basic fact is that only a handful of utilities in other states have pursued the fixed billing option. Most of these utilities are in the southern part of the United States.

In direct testimony in this case, Mr. Coppola provided similar testimony to that which he provided in the last case, which the Commission relied upon in large part to deny DTE's proposal.[125] The AG's concerns remain the same in this case, namely 1) that the new program would be duplicative and unnecessary, 2) that the new program would discourage energy conservation, and 3) that "warnings" proposed by the Company would create confusion and resentment on the part of customers. Based on the Commission's decision in the last rate case, objections from Staff and intervenors in U-20162 and this case, and Mr. Coppola's testimony, the AG recommends that the Commission reject DTE's request for the $900,000 of O&M expense and the capital expenditures request of $2.8 million.

G. Wellness Program

In Exhibit A-13, Schedule C5.11, witness Cooper shows wellness program expenses increasing from $2.2 million in 2018 to $4.5 million in the projected test year. This is a more than 100% increase in wellness program expenses. DTE has consistently spent between $1.8 million and $2.2 million on its "wellness" program

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[125] 9 Tr 3061-63.

during the 2014-2018 timeframe.[126] DTE failed to provide any explanation in testimony for how it plans to spend the additional funds or any studies to justify the expense.

In rebuttal testimony, Company witness Cooper disagrees with Mr. Coppola's proposed disallowance of $2.3 million of Wellness program expenses.[127] He states that the specific elements of the Wellness program were not finalized when he filed his direct testimony.[128] The AG takes issue with DTE proposing cost forecasts and recovery for programs with uncertain parameters, which are not specifically understood. On cross examination Mr. Cooper was pressed on this program and the lack of details contained in his direct and rebuttal testimony. The AG continues to argue that the contours of the Wellness program are not outlined well-enough by DTE to support recovery, and argues that the program is duplicative of other programs and benefits offered by the Company. When asked to elaborate on the program, Mr. Cooper provided the following:

> So similarly how the Company has created a culture of safety where can we focus on ensuring that our employees go home the same they come to work, we're focusing also now on developing a culture of health and well-being so that we can provide the right programs, the right opportunity so that our employees and their families get the -- in essence have the best opportunity to care for themselves and their health and their well-being.[129]

[126] 9 Tr 3063.

[127] 5 Tr 971.

[128] 5 Tr 971.

[129] 5 Tr 972.

While employee health is always a good goal, the Company has not laid out a reasonable, detail-oriented program that would support more than doubling current Wellness program expenditures.

Given the Company's failure to support its request for higher O&M expense for the wellness program, the AG recommends that the Commission remove the increase in expense of $2.3 million from the Company's projected O&M expense amount for the project test year.

H. Incentive Compensation Expense

In direct testimony, Mr. Coppola provides a summary of DTE's incentive pay plans and the amount of expense DTE seeks to recover in this rate case.[130] In total, DTE is looks to recover $47.6 million of employee incentive payments.[131] Based upon the information provided on page 49 of the revised direct testimony of Company witness Michael Cooper, $7.6 million pertains to the Annual Incentive Plan (AIP), $24.2 million to the Rewarding Employees Plan (REP), and $16.8 million pertains to the Long-Term Incentive Plan (LTIP).[132]

As the AG has argued in past cases and as Mr. Coppola notes again here in direct testimony, the three incentive plans proposed by the Company are too heavily skewed toward measures that directly benefit shareholders as opposed to customers. Additionally, the customer benefits presented by the Company are

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[130] 9 Tr 3064-66.

[131] 9 Tr 3064.

[132] 9 Tr 3064.

based on a faulty premise of historical cost savings and an expectation that future targets of performance will be achieved.[133] Mr. Coppola provides further, extensive discussion on the shortcomings of the Company's proposal in his testimony.[134]

On page 49 of his revised direct testimony, Mr. Cooper has included a table showing the components of the incentive compensation expense that the Company has included in the O&M expense for the projected test year. For the reasons described in Mr. Coppola's past testimony and his testimony in this case, the AG recommends that the Commission remove the entire $28.4 million related to financial performance measures. With regard to the portion of incentive compensation relating to operating measures, the AG is cognizant of the fact that in recent cases the Commission has allowed recovery of a portion of the short-term incentive pay related to operating performance measures for DTEE and Consumers Energy. In that vein, the AG recommends that the Commission allow recovery of that portion of incentive compensation expense that the Company has identified pertaining to operating performance measures, adjusted down to the level discussed below.

In the table on page 49 of Mr. Cooper's revised direct testimony, the Company shows $19.2 million of incentive compensation related to operating performance measures. However, as stated in Mr. Coppola's testimony, this amount assumes that 100% of the operating measures will be achieved at the target

[133] 9 Tr 3066.

[134] 9 Tr 3066-73.

level. Also as discussed in Mr. Coppola's testimony, the Company has achieved only approximately 30% of operating measures at the 100% target level or above in 2018. This fact needs to be taken into consideration in granting an appropriate amount of incentive compensation expense for operating measures.

In rebuttal, while supporting the inclusion of certain incentive compensation, Mr. Cooper states that customers also benefit from the Company maintaining its current debt rating and the avoided higher interest rates, plus keeping O&M expense below the rate of inflation.[135] Mr. Cooper was asked on cross about this notion of customers and shareholders benefitting jointly from certain aspects of DTE's business. First, he agreed that, for employees who participate in incentive plans, somewhere between 70% and 90% of the total compensation makes up "base pay."[136] He also agreed, subject to coming to agreement on what "basic" means, that customers should expect some basic level of performance from Company management for that base pay.[137] Obviously that is a given. He was then asked whether maintaining the current debt rating would be included in that "basic" level of performance.[138] In answer, he hedged some and stated that he would not necessarily agree with that.[139] When pressed, he stated that maintaining a credible debt rating is probably something customers could expect, but he was unwilling to

[135] 5 Tr 952.

[136] 5 Tr 966.

[137] 5 Tr 966.

[138] 5 Tr 966.

[139] 5 Tr 966.

commit to a solid answer.[140] The AG argues that being fiscally responsible and keeping O&M costs as low as possible should be a basic expectation for management employees to earn their base pay. Management does not need the additional "incentive compensation" to work toward maintaining the Company's current debt rating, which is certainly a part of their base responsibilities. Therefore any argument that incentive pay is necessary for management to do that work, and therefore ratepayers should pick up the tab for that incentive pay, is disingenuous and should be rejected. It is also disingenuous for the Company to state that customers get benefits from keeping costs below inflation when, in this very case, DTE has proposed to recover nearly $70 million of projected inflationary cost increases. There would be no benefits to customers from keeping costs below inflation if, in each rate case DTE gets to recover inflationary cost increases.

Also in rebuttal, Mr. Cooper disagrees with Mr. Coppola's analysis and conclusion about the level of operating measures achieved by DTE within the incentive compensation plans.[141] Mr. Cooper lists three areas of disagreement and prepared Ex. A-33, Schedule X2, which he filed with rebuttal.[142] His conclusion from the calculations he performed in that exhibit, which he stated that he performed to "correct Mr. Coppola's" Exhibit AG-1.39, was that DTE failed to achieve about 30% of its operating measures, on average.[143] To get to that

[140] 5 Tr 966-67.

[141] 5 Tr 968.

[142] 5 Tr 968.

[143] 5 Tr 969.

percentage, Mr. Cooper excluded performance measures achieved at threshold level and above, "financial measures and looked at just those for the threshold."[144]

DTE has set three levels of performance in the performance measures in order to guide the amount of incentive pay that can be paid out in a given year. First, there is a minimum, or "Threshold" level, second a Target level of performance, and third a Maximum level of performance.[145] The amount of incentive compensation for the short-term annual incentive that has been included in the forecasted expense in this rate case is based on DTE achieving Target level performance and not Threshold level performance.[146]

Looking a bit more closely at Exhibit A-33, Schedule X2, line 7 shows the number of operating performance measures achieved at Target level or above for each of the plans and companies that are part of the incentive compensation expense. Line 8 shows the total number of operating measures included in each plan. So, to calculate the percentage of operating measures that were achieved at target or better within each plan,[147] one would divide line 7 by line 8. So, for DTE and DTE LLC, under the AEP Performance Plan the success rate would be 50% for each company. For the nuclear measures under the AEP plan, the Company achieved around 70% of the operating measures. Moving to the REP incentive plan,

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[144] 5 Tr 969.

[145] 5 Tr 969-70.

[146] 5 Tr 970.

[147] Given that the compensation expense was calculated based on the Company achieving a Target level of performance.

DTE and DTE LLC each achieved 6 measures at Target or better out of 13 total operating measures. That is less than 50%, or approximately 45%. And the Nuclear group achieved 4 out of 6 operating measures, or a 66% success rate. When those 6 percentages are averaged it comes out to a 55% success rate.

In response to DR AGDE-6.185, which is included as Ex. AG-1.47, Mr. Cooper prepared the same calculation just performed above for 2018 to get to the 55% success rate. The attachment to AGDE-6.185 also shows that success rate was higher in 2017, but around 54% in 2016. So in at least two out of the last three years the success rate at Target or above has been around 55%, meaning that 45% of the operating measures were not achieved at the Target level. Accordingly, Mr. Coppola and the AG have proposed that, as an alternative to complete disallowance, the Commission disallow 50% of the short-term incentive plan, because the Company has not historically achieved 100% of its operating performance measures.

Accordingly, based on the above and Mr. Coppola's testimony, the AG recommends that the Commission allow recovery of only 50% of the $19.2 million, or $9.6 million.

The AG also points out that there is a portion of incentive compensation that DTE includes in capital additions and rate base, which is not included in the chart on page 49 of Mr. Cooper's revised direct testimony. That chart only includes the projected incentive compensation pertaining to O&M expense for the projected test year. In addition, each year the Company allocates and capitalizes a portion of both short-term and long-term incentive compensation, which is included in rate base.

In response to discovery, the Company provided information on the amount of incentive compensation capitalized for 2018 through 2021.[148]

The amounts pertaining to 2018 through the end of the projected test year are $25.2 million for short-term compensation and $19.2 million for long-term compensation. These amounts reflect the Commission's prior decisions to allow recovery of only incentive compensation pertaining to operating performance measures for the short-term incentive plans and no recovery for long-term incentive compensation. Exhibits AG-1.11 and AG 1.40 show the amounts prorated and pertaining to each forecasted period. The AG recommends that the Commission remove these amounts from projected rate base and that the Commission direct the Company to, in future rate cases, identify the amount of capitalized incentive compensation included in projected rate base for the projected periods in the same detail as provided in the chart on page 49 of Mr. Cooper's revised direct testimony. Furthermore, the Company should affirm in filed testimony that it has removed from historical rate base all incentive compensation previously disallowed by the Commission. This information will facilitate the analysis of allowable incentive compensation included in rates and will ensure its accuracy.

In rebuttal, Company witness Adella Crozier disagrees with the AG's proposed disallowance of capitalized incentive compensation because DTE witness Cooper believes that incentive compensation should be part of a total compensation

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148 Exhibit AG-1.40.

package.[149] It is instructive that Ms. Crozier has no training or experience in regulatory accounting.[150] Also in rebuttal, as support for her position, she states that it has been a part of DTE's practice to include a portion of incentive compensation in O&M and in capitalized plant costs.[151] The AG argues that the fact that DTE has capitalized a portion of incentive compensation in the past does not mean that it should be included in rate base if the Commission decides that it does not belong there.

Also in rebuttal Ms. Crozier states that the Commission disallowed some of the incentive compensation from O&M expense in U-20162, but does not specify any Commission disallowance for the amounts capitalized.[152] When questioned on cross, Ms. Crozier was uncertain as to whether the Company disclosed in U-20162 how much of the long-term incentive compensation and how much of the short-term incentive compensation had been included in the rate base for the historical and projected periods.[153] That information was not disclosed by DTE in U-20162. Additionally the issue of capitalized incentive compensation was not addressed by the Commission in U-20162.

As noted, the AG has proposed that there by consistency in the disallowance of incentive compensation from O&M expense versus capitalized amounts. If the

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[149] 4 Tr 504-05.

[150] 4 Tr 509.

[151] 4 Tr 510.

[152] 4 Tr 510-11.

[153] 4 Tr 510-12.

Commission disallows certain portions of incentive compensation, such as the long term incentive portion from O&M, then the portion that the Company has included in rate base should also be disallowed. Similarly, if the Commission disallows the portion of short-term compensation pertaining to financial measures from O&M expense, consistency would dictate that the amount capitalized in rate base should also be removed.

Finally, on page 19 of her rebuttal Ms. Crozier states that if the Commission agrees with the AG's recommendation, that it should only make the disallowance prospective.[154] When questioned on cross, Ms. Crozier agreed that this was so that DTE would not have to write off incentive compensation amounts that it decided to capitalize.[155] That was the only reason she was able to offer on the stand.[156]

Accordingly, the AG continues to recommend that the Commission follow the AG's recommendations as laid out above and in Mr. Coppola's testimony.

Total Recommended Adjustments

The AG recommends total reductions to O&M expenses of $128.8 million as discussed above and as laid out in Mr. Coppola's testimony. Those reductions are summarized in the following table and Exhibit AG-1.41 provides additional details.

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[154] 4 Tr 512.

[155] 4 Tr 514.

[156] 4 Tr 514.

Summary of O&M Expense Reductions	Amount ($Millions)
Inflation Expense Adjustment	$ 69.8
Power Generation	3.1
Distribution Operations	7.9
Credit/Debit Card Fees	4.7
Uncollectible Accounts Expense	2.1
Employee Incentive Compensation	38.0
Employee Benefits & Other	3.2
Total Reduction	**$ 128.8**

IV. CAPITAL EXPENDITURES AND RATE BASE

With the help of Mr. Coppola, the Attorney General analyzed the Company's forecasted capital expenditures by major department or functional area and has identified more reasonable expenditure levels that the Commission should adopt.

A. Contingent Capital Expenditures

DTE is including total contingency costs of $17,745,000 in its forecasted capital expenditures for 2019 and the 16 months ending April 2021.[157] This contingency amount should be excluded from the calculation of rate base for the projected test year. The fact that these added costs are contingent means that they

[157] 9 TR 2970.

may not be spent in whole or in part, and thus it is not fair or reasonable for the Company to recover the depreciation expense and the return on the investment on potential costs that may not be actually incurred but have been added to rate base.[158]

The $17,745,000 of contingency costs includes $14.6 million of contingency costs related to the Combined Cycle Plant being built by the Company, for which it received separate approval in U-18419.[159] Page 126 of the Commission's order of April 27, 2018 in the Combined Cycle Plant case, No. U-18419, states that only actual costs shall be recovered through rates.

In DTE's prior electric rate case, U-20162, the Commission addressed the issue of contingency costs and determined that contingency amounts should be excluded from capital expenditures and rate base.[160] The Commission similarly affirmed this exclusion in its order in Case Nos. U-18255, U-18124, U-18014, U-17999, U-17990, U-17767 and U-17735. Accordingly, the Attorney General recommends that the Commission exclude $17,745,000 from the forecasted capital expenditures in this rate case filing.

B. Distribution Operations

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[158] 9 TR 2971.

[159] 9 TR 2970-71.

[160] *In the matter of the Application of DTE Electric Company*, MPSC Case No. U-20162, May 2, 2019 Commission Order, p 6.

DTE forecasts nearly $2.0 billion in capital expenditures for the 28 months ending April 2021 for additions to Distribution Plant.[161] The Attorney General has identified certain capital expenditure reductions applicable to several areas.

<u>Emergent Replacement Programs</u>

In his direct testimony, Mr. Coppola provides a summary of the Company's forecasted capital expenditures for three categories of Emergent Replacement Programs: Storm-related, Non-Storm, and Substation Reactive.

> The total amount of capital expenditures for 2018 for these three programs was $345.9 million. The Company has forecasted $245.7 million for 2019, $82.6 million for the four months ending April 2020, and $247.4 million for the 12 months ending April 2021. According to Mr. Bruzzano's direct testimony, the Company decided to determine the forecasted amounts by using a five-year historical period of expenditures from 2014 to 2018 in order to normalize the expenditure level, and use as a base to apply projected annual inflation adjustments.[162]

Underlying Mr. Coppola's proposed adjustments in these areas is the basic premise that DTE has not provided any evidence to show that it faced inflationary cost increases in prior years or that it will face inflation cost increases in future years to the forecasted levels. Additionally and troublingly, DTE's calculations to arrive at its forecasted capital expenditures attempt to retroactively capture inflation cost increases by applying inflation adjustments to prior-year amounts from 2014 to 2018 in order to arrive at an average base amount for the five-year period. Such retroactive recovery of costs should not be permitted.

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[161] Ex. A-12, Sched. B5.4, p 1.

[162] 9 Tr 2972, citing to the Direct Testimony of Marco Bruzzano, p 99, and Ex. A-12, Schedule B5.4, p 3.

Although the AG agrees with the five-year normalization approach to forecast capital expenditures for future years used by DTE,[163] it should be done using actual capital expenditures from prior years, not by recasting numbers with additional assumed costs for prior year inflation. If any inflation was experienced in those prior years, it is already reflected in the actual amounts. It is simply an unsupportable fabrication to inflate historical costs to arrive at an adjusted historical base and to then further inflate those costs for future years with projected inflation factors.

With regard to the future inflation rates, DTE arrived at the rates by using blended rates of internally estimated wage inflation of 3% and the CPI-Urban index forecasted inflation rate of approximately 2%.[164] In prior rate cases, the Commission has disallowed the use of this blended approach and approved the use of the CPI-Urban index, and it should continue to do so in this case.

The burden should be on the Company to demonstrate that it has actually experienced inflationary cost increases and will likely experience inflation cost increases in the future. However, there has been no such evidence presented by the Company in this case or prior rate cases. To the contrary, the Company boasts about having achieved actual operation and maintenance cost levels that are $222 million below the inflation adjusted amounts from 2009 to 2018.[165] This is clear

[163] Ex. A-12, Sched. B5.4, p 3.

[164] Ex. A-13, Schedule C5.15.

[165] Revised Direct Testimony of Michael Cooper, p 52.

evidence that the Company has not experienced inflationary cost increases in the past and is not likely to experience them for 2019 and through the end of the projected test year.

<u>Recommendations</u>

The AG recommends that the Commission adopt the specific adjustments for DTE's forecasted capital expenditures for emergent capital programs as laid out in Mr. Coppola's direct testimony.[166] The specific details are all laid out in Mr. Coppola's testimony. With regard to the Storm-related capital expenditures, the AG proposes that the Commission approve the actual five-year average amount of $101,136,000 for the 2014-2018 period, an adjustment of $19,445,000. For Non-storm capital expenditures, the AG proposes that the Commission approve the actual five-year average amount of $101,141,000 for the 2014-2018 period, an adjustment of $19,005,000. And for the Substation Reactive Program expenditures, the AG recommends that the Commission approve the actual five-year average amount of $31,657,000 for the 2014-2018 period, an adjustment of $6,118,000. Exhibit AG-1.3 shows the calculations used to arrive at all of those amounts.

If the Commission does decide to approve some inflation adjustment for any of the above expenditures, the AG recommends using an inflation rate of no more than 2%, which is equivalent to the CPI-Urban index, beginning in 2020. Those calculations are also provided in Mr. Coppola's direct testimony.[167]

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[166] 9 Tr 2974-77.

[167] 9 Tr 2974-77.

C. New Customer Connections and New Business Projects

On page 4 of Exhibit A-12, B5.4, the Company shows the two major capital programs for New Customer Connections and New Business Projects. The Company has taken a similar approach in forecasting future capital expenditures for these programs as it did for the Emergent Replacement Programs discussed above, by adding an inflation factor to the historical capital expenditures.

As with the Emergent Replacement Programs, there is no basis for the Company to apply an inflation factor to the 2018 capital spending level to project capital spending over the next two years. Accordingly, the AG recommends that the Commission approve the same amount of capital expenditures incurred in 2018 for future periods, prorated accordingly for stub periods. The AG proposes that the Commission approve the actual amount of $108,257,000 spent in 2018 for future periods for the combined New Customer Connections and New Business Projects.[168] This is an adjustment of $12,582,000 off of DTE's proposal.[169] Additionally, if the Commission does decide to approve some inflation adjustment for any of the above expenditures, the AG recommends using an inflation rate of no more than 2%, which is equivalent to the CPI-Urban index, beginning in 2020. Those calculations are also provided in Mr. Coppola's direct testimony.[170]

D. Facility Relocation Projects

[168] Ex. A-12, Schedule B5.4, p 4, line 11, column (b); 9 Tr 2978.

[169] See Ex. AG-1.4 for calculations.

[170] 9 Tr 2978-79; Ex. AG-1.4

On page 4 of Exhibit A-12, B5.4, the Company has subdivided the capital expenditures for Relocation Projects between the larger project of relocating electrical facilities near the Gordie Howe International Bridge (GHIB) and smaller routine relocation projects.

With regard to the projected capital expenditures for the GHIB project, the AG recommends that the amount of $8,950,000 to be spent in 2019 and 2020 be disallowed. This amount represents half of the incremental cost of relocating the Company's electrical distribution facilities at the bridge plaza or surrounding area. On page 4, line 15, of Exhibit A-12, Schedule B5.4, the Company shows the gross amount of capital expenditures of $12.3 million in 2019 and $5.6 million in 2020. However, according to the Company half of this incremental cost will be paid by the GHIB Authority and those payments supposedly are reflected in the Contributions in Aid of Construction (CIAC) on line 17 and 20 of the exhibit.

In discovery, the Company was asked to explain why this project will require an additional $18.9 million in capital expenditures, on top of the $10.9 million spent in 2018.[171] In several responses, the Company stated that the scope of the project changed, requiring a budget increase of $18.5 million, of which the Company will be responsible for half.[172] The Company also stated that it originally proposed vacating its facilities from the Port of Entry (POE), but the Windsor Detroit Bridge Authority (WDBA) deemed the plans to be cost prohibitive. Therefore, the

[171] Ex. AG-1.5.

[172] The amounts provided in discovery responses are slightly different than the amounts shown in Exhibit A12, Schedule B5.4, likely due to the timing of when the original and incremental expenditures will be incurred.

Company and the WDBA apparently proceeded with an alternative plan. However, now the parties are finding that soil conditions prevent the location of the DTEE facilities at the originally planned site and relocation to a different site is necessary.

This relocation raises questions about the competency of the original work done and the decision to choose the original location. In addition, this is work specifically required to benefit the WDBA at an extraordinarily high cost, which is now nearly $29 million. The other customers of the Company do not benefit from these capital expenditures. Therefore, the AG argues that any additional costs to relocate the facilities should not be paid by the rest of DTEE's customers by including them in rate base. The entire incremental costs to complete the relocation should be paid by the WDBA. If the Company agreed to pay for half of the incremental costs, then it should absorb those costs and not burden its customers with higher costs.

Therefore, the AG recommends that the Commission remove $6,150,000 of capital expenditures from 2019, $934,000 for the four months ending April 2020, and $1,867,000 for the 12 months ending April 2021. This is a total disallowance of $8,950,000 for the 28 month period and assumes that the Company has included half of the costs for the incremental project costs in the CIAC amounts in Exhibit A-12, Schedule B5.4, page 4, line 17 or 20. If the Company has not included the appropriate amount of CIAC, then a higher amount up to the total amount shown on line 15 of the exhibit for 2019 and 2020 should be disallowed.

E. Disallowances of Capital Expenditures for Electric System Equipment

On page 4 of Exhibit A-12, B5.4, the Company has identified the three capital programs under Electric System Equipment. The AG finds the 2018 capital spending levels to be reasonable. However, as stated earlier, there is no basis for the Company to apply an inflation factor to the 2018 capital spending level to project capital spending over approximately the next two years. Therefore, the AG recommends that the Commission approve the same amount of capital expenditures incurred in 2018 to future periods and appropriately prorated for stub periods.

That amount is $51,967,000 spent in 2018 for the three combined programs, as shown on line 26, column (b) of Exhibit A-12, Schedule B5.4, page 4. This is $5,992,000 less than DTE's request.[173] If the Commission decides to approve some inflation adjustment for future capital expenditures for these programs, it should approve no more than a 2% inflation rate, equivalent to the CPI-Urban index, beginning in 2020.[174]

F. Disallowances of Capital Expenditures for Strategic Capital Programs

On page 1 of Exhibit A-12, B5.4, the Company has identified the three major capital programs under Strategic Capital Programs. The total amount of proposed spending in these three programs over the forecasted 28 months is $912.0 million. On page 16 of his direct testimony, Mr. Bruzzano has included Table 6, which compares the amount spent on Distribution capital programs in 2018 versus the amount that the Company had proposed and received funding for in Case No. U-

[173] Ex. AG-1.4.

[174] Ex. AG-1.4.

20162. The table shows that, in total for the three Strategic Capital Programs, the Company underspent the projected amount by $126.2 million, or 31% less than it had forecasted.

In discovery, the Company was asked to explain its commitment going forward to spend funding for those programs if approved by the Commission. In two responses, the Company provided somewhat contradictory and hedged answers.[175]

To establish whether 2018 was an anomaly, Mr. Coppola reviewed the capital spending for these programs for the 9 months ended September 2019 against the forecasted expenditures for the same period. The result of that analysis is that the Company has again significantly underspent its forecasted capital expenditures during the first nine month of 2019 by approximately 21%, and in some categories, such as Technology and Automation, by as much as 32%.[176]

The only conclusion to be drawn from the historical and 2019 year-to-date capital spending is that the Company is not likely to reach the spending levels for the Strategic Capital Programs proposed in Exhibit A-12, Schedule B5.4, page 1. The commitment to spend the requested amounts is consistently reneged upon, once other programs require more funding. Weather events occur, to some degree or another, every year and will continue to do so in the future. If the Company's commitment to spend on these programs is so highly dependent on weather events, then it is not a commitment at all.

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[175] See Ex. AG-1.7.

[176] Ex. AG-1.6.

Therefore, as a reasonable adjustment, the AG proposes that the Commission remove 20% of the proposed capital spending for 2019 and future periods. The 20% is in line with the overall underspending percentage for Strategic Capital Programs occurring during the first 9 months of 2019, and is still significantly below the 31% that occurred in 2018. As a result of this adjustment, the AG recommends that the Commission remove $182,341,000 total, for the 28 months.[177] The calculations supporting these adjustments are shown in Exhibit AG-1.6.

G. Power Generation Plant

In direct testimony, Mr. Coppola proposes adjustments to the Company's projected capital expenditures for power generation facilities. On page 1 of Exhibit A-12, Schedule B5.1, the Company forecasted both Routine and Non-Routine capital expenditures of $697.3 million for 2019, $295.4 million for the four months ending April 2020, and $519.8 million for the 12 months ending April 2021 for Power Generation Routine capital projects. Mr. Coppola identified total adjustments of $43.0 million in Routine projects and $40.8 million in Non-Routine projects.

Proposed Adjustments to Routine Power Generation Projects

1. 2019 Routine Projects

As laid out in testimony,[178] Mr. Coppola identifies total adjustments of $13.2 million in routine projects, related to five separate 2019 projects. The details of these projects and adjustments are laid out on pages 34-36 of Mr. Coppola's direct

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[177] 9 Tr 2985.

[178] 9 Tr 2987-90.

testimony.[179] Exhibit AG-1.8 provides further detail. The AG adopts this recommendation and recommends that the Commission remove the $13,198,000 from capital expenditures for 2019.[180]

2. 2020 Routine Projects

As laid out in testimony,[181] Mr. Coppola identifies total adjustments of $17.044 million in routine projects, related to eight separate 2020 projects. The details of these projects and adjustments are laid out on pages 37-41 of Mr. Coppola's direct testimony.[182] Exhibit AG-1.9 provides further detail. The AG adopts this recommendation and recommends that the Commission remove the $17,044,000 from capital expenditures for 2019.[183]

3. 2021 Routine Projects

Similar to the 2019 and 2020 costs, Mr. Coppola identifies total adjustments of $12.8 million in routine projects, related to seven separate 2021 projects.[184] As noted, the projects do not have dated or approved PAT forms or have forms with no designated or approved capital spending for 2021. Additionally, the amounts forecasted by DTE appear to be "ballpark" amounts as a placeholder for the purposes of preparing a rate case forecast. The Commission has previously rejected

[179] 9 Tr 2988-90.

[180] Ex. AG-1.12.

[181] 9 Tr 2990-95.

[182] 9 Tr 2991-95.

[183] Ex. AG-1.12.

[184] 9 Tr 2995.

such placeholder amounts and the projects and cost estimates are premature for inclusion in this rate case. Exhibit AG-1.10 provides further detail. The AG adopts this recommendation and recommends that the Commission remove the $12,800,000 from capital expenditures for 2019.

Proposed Adjustments to Non-Routine Power Generation Projects

In direct testimony, Mr. Coppola identifies $40.785 million of projected capital expenditures for non-routine power generation projects that should be removed.[185] The recommendation relates to expenditures for Monroe Bottom Ash Basin Closure. The AG adopts this recommendation and accordingly recommends that the Commission remove the $40.785 million. As noted, the AG's concern is that the program may change and that there are no definitive rules set by the state agency. Until EGLE issues new compliance rules that have been approved by the EPA, the AG feels that it is premature to spend millions of dollars on this project. Therefore, the AG recommends that the Commission remove the projected capital expenditures of $40,785,000 for this project for 2019 and through the end of April 2021 from this rate case.

In total, the AG recommends that the Commission remove capital expenditures of $83.8 million pertaining to Power Generation capital projects.[186]

H. Information Technology Projects

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[185] 9 Tr 2995.

[186] Ex. AG-1.12.

On page 1 of Exhibit A-12, Schedule B5.7, the Company shows the historical and projected capital expenditures for Information Technology (IT) projects. During 2018, the Company spent $79.2 million on IT projects. However, for 2019 the Company has projected a major escalation in capital spending to $98.3 million, followed by $35.1 million in the four months ending April 2020 ($105.2 million annualized) and $136.7 million for the 12 months ending April 2021.

The Company has proposed over 100 IT projects to be undertaken, or that will be on-going over the 28-month forecasted period. The AG has identified 7 projects that do not appear to qualify as priority projects and should be removed from the capital expenditures approved in this rate case with total projected capital spending of $54.8 million. The 7 projects are: Applied Innovation, Digital Innovation, Success Factors Program, Web Portal Rebuild, Bill Redesign, Pay to Purchase, and the Fixed Bill project.

Those projects and their related proposed disallowances are discussed in Mr. Coppola's direct testimony, pages 45-53.[187] The specific calculations are provided in Ex. AG-1.14. The AG adopts that testimony and reasoning here and accordingly recommends that the Commission disallow that $54.8 million in spending.

In rebuttal, Company witness Mr. Griffin disagrees with Mr. Coppola's proposed disallowances for forecasted expenditures for the various IT systems.[188]

[187] 9 Tr 2998-3006.

[188] 8 Tr 2461.

On page 2 of his rebuttal testimony, beginning on line 21 and continuing into the next two and a half pages, Mr. Griffin disagrees with Mr. Coppola's proposed disallowance of capital expenditures for the Purchase to Pay (P2P) system implementation project.[189] On page 3, lines 10 to 12, Mr. Griffin states that the Commission "approved" $1.9 million of spending on this project in U-20162.[190] This statement is misleading. In U-20162, the Commission included that $1.9 million in capital expenditures in the last rate case as no party challenged those expenditures. The Commission did not specifically call out that project in its order in U-20162 and specifically approve the $1.9 million in capital expenditures.

On line 13 of page 3 then, Mr. Griffin states that cancelling the project now would "wipe out" the value of that investment.[191] The total cost of the project is $6.7 million.[192] This means that there is still at least another $4.7 million to be spent after 2018. If, as Mr. Coppola contends in his testimony, there is no economic justification for the project, it would be much better for customers to write off the $1.9 million "investment" rather than spending another $4.7 million on an uneconomic project.

On lines 17-20 of page 3 of his rebuttal Mr. Griffin lists several items to explain why this P2P system is important to the Company and should be funded. On cross Mr. Griffin was asked about any cost-benefit analyses that were performed

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[189] 8 Tr 2463-66.

[190] 8 Tr 2464.

[191] 8 Tr 2464.

[192] Ex. AG-1.13, p 7.

to support the P2P system implementation.[193] While he discussed some of the nebulous, unquantifiable value surrounding asset health and the need to update this specific system, when pressed Mr. Griffin admitted that he is not aware of any study conducted to indicate that the system or these items of importance will be of value to customers.[194] The AG points out that while the Company either has not attempted to or cannot show any specific value to customers stemming from the P2P system implementation, the Company has no problem identifying the $6.7 million level of expense it wishes to recover from customers. Under DTE's rationale, if there is no "economic threshold" to be met and no requirement that any kind of benefit be examined or shown, then any project would be acceptable.

Still on page 3 of rebuttal, lines 21 to 25, and also during cross examination, Mr. Griffin discusses the fact that P2P is part of a larger enterprise system and fits in with DTE's plan to migrate to cloud computing in 2025 through the S/4 system.[195] This is a tactic that DTE often employs, arguing that although the current system may not technically be at "end-of-life" yet, the vendor has already stopped supporting parts of the system, or the Company needs to start transitioning so that it is ready when that system does reach end of life. In this case, that transition is apparently at least a 6-year endeavor, based on the 2025 date provided by DTE. While DTE would undoubtedly like a blank check to continually upgrade its IT

[193] 8 Tr 2489-90.

[194] 8 Tr 2489-90.

[195] 8 Tr 2490-91.

systems and always be at the very latest, cutting edge, the relative functionality of systems must be balanced against affordability to customers.

Additionally, Exhibit AG-1.55 shows that there is no Company approval as of yet to proceed with S/4 implementation. Accordingly, the AG argues that any discussion to justify the P2P based on the implementation of the S/4 system is premature at this time.

On page 5 of his rebuttal, Mr. Griffin states that one of the benefits of the P2P system is to increase supplier satisfaction and diversification.[196] On cross, Mr. Griffin admitted that there is nothing currently preventing DTE from diversifying its supplier base without this system.[197] Additionally, the AG argues that customers should not be paying millions of dollars in order to make sure that DTE's suppliers are "satisfied."

At best, it appears that the system migration will happen 6 years from now. Accordingly, including those costs in rates now to replace a purchasing system that is still functioning is, at best, premature.

<u>Success Factors Program</u>

On page 6 of his rebuttal testimony, Mr. Griffin discusses DTE's "Success Factors" program. The "Success Factors program" is a fancy name for a human resources management system that processes payroll and related employee functions.

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[196] 8 Tr 2493-94.

[197] 8 Tr 2494.

In rebuttal, Mr. Griffin disagrees with Mr. Coppola's proposed disallowance of the capital expenditures for this program.[198] Mr. Griffin states that the Commission "approved" $1.6 million of spending on this system in U-20162.[199] Similar to the P2P system, by "approve" Mr. Griffin means that DTE included those dollars in capital expenditures in U-20162 and no party challenged those expenditures. The Commission did not specifically call out that project in its order in U-20162 or specifically approve the $1.6 million in capital expenditures.

On lines 7 to 9 of page 6 of Mr. Griffin's rebuttal he states that by cancelling the project now the value of the investment would be lost.[200] The total cost of the project is $11.7 million.[201] This means that there is still at least another $10 million to be spent after 2018. If, as Mr. Coppola contends in his testimony, there is no economic justification for the project, it would be much better for customers to write off the $1.6 million "investment" rather than spending another $10 million on an uneconomic project.

On lines 17-19 of page 6 of his rebuttal, Mr. Griffin states that failing to fully implement the Success Factors program would allow the system to lapse into unsupported obsolescence.[202] In the discovery response included in Exhibit AG-1.56, Mr. Griffin discussed what "unsupported obsolescence" means with regard to

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[198] 8 Tr 2467.

[199] 8 Tr 2467.

[200] 8 Tr 2467.

[201] Ex. AG-1.13, p 7.

[202] 8 Tr 2494.

this specific system. From the response, it is clear that unsupported obsolescence means that the vendor is no longer issuing new updates to the system, the reason for which is that the vendor wants to sell DTE its new system, Kronos. This appears to be a form of planned obsolescence by software vendors and does not necessarily indicate that DTE's system is obsolete.

The discovery response also indicates that this system replacement is also tied in with the S/4 cloud computing change, which, as already discussed, has not yet been approved by the Company.[203] Accordingly, the AG continues to recommend that these costs be disallowed.

Customer Bill Redesign

Beginning on line 14 on page 9 of Mr. Griffin's rebuttal, he disagrees with Staff's and the AG's proposed disallowance of approximately $5.5 million of capital expenditures for a project to redesign the customer bill.[204] Through the end of 2021 the total cost of this project is at least $7 million.[205] Mr. Griffin also indicated on cross that there is a chance that additional costs could arise before the bill is in its final form, for example if the Company adopted new rates or got feedback from customers requesting that the bill be presented in a different way.[206]

[203] 8 Tr 2495.

[204] 8 Tr 2495.

[205] Ex. AG-1.13, p 6.

[206] 8 Tr 2496-97.

In rebuttal, Mr. Griffin identifies 2,000 bills that are currently manually adjusted as one of the main reasons behind this request.[207] On cross Mr. Griffin also identified some other areas that the bill redesign could add value, such as reduced materials costs and reduced customer confusion.[208] It is unclear how much cost reduction could be expected from these reasons, but since the elimination of the need to manually adjust the 2,000 bills was the reason provided in rebuttal, the AG explored that issue.

Exhibit AG-1.57 provides three examples of bills where an adjustment line is shown in the electric bill, with no current explanation for that adjustment. These are examples of the 2,000 weekly bills that the Company proposes to change and the source of the confusion and calls to DTE.[209] During cross, the first sample bill was discussed with Mr. Griffin.[210] He discussed both that the specific customer got a bill adjustment and that they are enrolled in DTE's Shutoff Protection Plan.[211] He went on to state that sometimes these customers will call in because of confusion over their bill.[212] At base, the AG does not understand why DTE is unable to make a programming fix to the current bill, where the adjustments discussed are footnoted somewhere in the bill or next to the explanation box, providing the very details Mr.

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[207] 8 Tr 2471.

[208] 8 Tr 2497-98.

[209] 8 Tr 2498.

[210] 8 Tr 2498-2500.

[211] 8 Tr 2499-2500.

[212] 8 Tr 2500.

Griffin provided during cross examination. Additionally, it would be costly and imprudent to spend $7 million to implement a programming fix to redesign a bill for 2,000 bills that require a few more details. While there may be some other tangential benefits, DTE did not lay those out in testimony or present any monetary analysis that it would be worth the millions of dollars of increased customer costs. Finally, DTE did not present any evidence about other options the Company considered to address the problem at a lesser cost.

Digital Engagement Group Establishment

At a general level, this project entails establishing a customer engagement group and designing and implementing new or upgraded software systems.[213] Mr. Griffin disagrees in rebuttal with the AG's and Staff's testimony that the project is not well defined or justified and that the proposed $9 million of capital spending for the project should be disallowed.[214] On page 12, lines 7-12 of his rebuttal, Mr. Griffin describes that 73% of the customer interactions are done through digital channels and he mentions the Interactive Voice Response system.[215] That system is the phone answering system that the Company uses to first answer customer calls with an automated menu of options.[216] The reason that DTE labels this a "digital system" appears to be because customers push some buttons on their phones to provide answers to automated questions before talking to a customer service

[213] 8 Tr 2502.

[214] 8 Tr 2473.

[215] 8 Tr 2502.

[216] 8 Tr 2502.

representative. Based on Exhibit AG-1.61, those phone calls are a significant portion of the customer interactions through what Mr. Griffin labels as "digital channels." This is not reasonable support for a multi-million dollar project.

On lines 14 to 25 of page 12 of his rebuttal, Mr. Griffin discusses additional upgrades to the Company's customer service system for customers to process more move-ins and move-outs on their own through the website. Based on Mr. Griffin's discovery response contained in Exhibit AG-1.58, the two main obstacles to customers processing more move-ins and move-outs on the website are Company business rules or customers terminating transactions prematurely.[217] These reasons have little or nothing to do with the need to make additional system upgrades.

As noted on cross, Mr. Griffin forecasted approximately $9 million in capital expenditures for 2020 for the establishment of the Digital Engagement Group.[218] On page 13 of his rebuttal he discussed other features that the Company would seek to implement with this project, specifically during the first period.[219] When asked whether the features that he mentioned in rebuttal could be implemented within the specified timeframe and budget or whether there may be additional costs, Mr. Griffin indicated that there may be additional projects that would stem from initial

[217] Ex. AG-1.58.

[218] 8 Tr 2506.

[219] 8 Tr 2506.

efforts that would incur costs beyond the test year.[220] The actual response on cross examination is instructive:

> The DE Group's responsibility is to work all of these areas, it's not wholly responsible for the projects that would stem from their efforts. As an example, the Digital Experience Group would be the front end of the design process that would design some of the projects that are upcoming. So while it would work often on the front end of these projects, the projects themselves might go past the time period that this is expressed for. So they're basically a design and function organization. The IT area would then implement the projects when it went into implementation. DEG would pick it back up when it's at the implementation has begun, and therefore we would be collecting customer feedback on the designs and so on. There's a -- They don't operate the entire project themself, so there would be investment in these projects potentially beyond the test year.[221]

This is a very vague and open-ended answer to the question of additional costs related to the Digit Engagement Group project and leaves open the possibility for ever increasing and expanding costs. As the Company has failed to quantify any cost savings from having customers do more transactions on their own online, and is unable to identify how much additional spending will be required and over what timeframe, the AG continues to recommend that the Commission disallow all of the requested cost recovery for the Digital Engagement Group Establishment project.

Web Portal Rebuild and Transformation

On page 13 of his rebuttal, beginning at line 21, Mr. Griffin discusses the Web Portal Rebuild and Transformation project, which includes a $17 million

[220] 8 Tr 2506-07.

[221] 8 Tr 2506-07.

requested increase to upgrade the current Company website.[222] Mr. Griffin notes that the website has a 72% satisfaction rate, which is the lowest of any of DTE's "digital channels."[223] He also noted that through the rebuild the Company hopes to increase self-service capabilities to customers, which could reduce labor costs to the Company.[224] On cross Mr. Griffin was asked whether the Company has quantified any of the cost savings from the labor reductions that he discussed in rebuttal.[225] Mr. Griffin had anticipated this question and had some numbers prepared for possible annual savings based on a dollar-amount-per-call figure and decreased labor costs.[226] The ALJ and Commission should give no weight to these numbers as they are completely unsupported by DTE and were provided for the first time on the stand.[227] Staff and Intervenors had no chance to vet the Company's internal savings forecasts.

Also on page 15 of his rebuttal, Mr. Griffin states that the web transformation will reduce the current load up time of web pages to improve customer experience.[228] According to Mr. Griffin's response to a discovery request, the Company's goal is to reduce its average load time for any transaction from 6

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[222] 8 Tr 2509.

[223] 8 Tr 2476.

[224] 8 Tr 2509-10.

[225] 8 Tr 2510.

[226] 8 Tr 2510-11.

[227] 8 Tr 2511-12.

[228] 8 Tr 2476.

seconds to 3 seconds, a 3 second reduction.[229] The AG argues that a 3-second reduction is not sufficiently perceptible to customers to justify a portion of the $17 million to be spent on this project.

The AG continues to argue that the Commission should deny DTE's request for a $17 million outlay to upgrade its website. The record does not contain adequate or reliable evidence that customers would see value anywhere near levels that would justify such a tremendous expenditure.

Applied Innovation

On page 16 of his rebuttal, Mr. Griffin responds to Mr. Coppola's testimony proposing disallowance of approximately $5 million in capital spending for the Applied Innovation project.[230] The forecasted cost for this program is $8 million between 2020 and 2021.[231] When questioned on cross, Mr. Griffin noted that the Company plans to continue this spending, at $4 million/year, indefinitely.[232] So, besides the $8 million identified by DTE in this case, there are millions of dollars in continuing costs that the Company will be seeking on an indefinite basis.

In a discovery request, which is included in Ex. AG-1.59, the AG asked the Company to explain what it is that this system will do to support innovation initiatives. While the AG understands that DTE has these 39 "innovation

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[229] 8 Tr 2414-15.

[230] 8 Tr 2477.

[231] 8 Tr 2515.

[232] 8 Tr 2515-16.

initiatives" that it believes the Applied Innovation system will deliver/address,[233] 1) they are all extremely vague, high-level projects with inadequate detail and 2) it is still unclear what type of actual *system or program* DTE is proposing to develop for the $8 million + that it is requesting. When asked on cross-examination to explain, Mr. Griffin first gave a circular answer, stating that the money would go to support the innovation initiatives discussed in the first part of Exhibit AG-1.59.[234] Obviously that is an unhelpful answer and does not address where the money would go or how it applies to the innovation initiatives. Mr. Griffin was asked about this further on cross:

> Q I guess I'm still -- I guess I'm still uncertain where that money is going. Is that money going to salaries? Is it going to -- I mean, is this kind of a think tank?
>
> A So some of the money does go to salaries, but the majority of it would be salaries to actually build and deploy the systems listed on the list.
>
> Q Salaries to build and deploy the systems. So it is salaries?
>
> A Some of it is salaries, yes. Some of it is technology. For example, if I could use an example, there is a setting here around drones. There is some ideas about how the Company might use drones. There would be money in there for also buying that equipment, paying people to program the software that would drive that equipment. So it's just like any other project that's in IT that has typically hardware and software components.
>
> Q Do you know what percentage of that money would go to salaries?
>
> A I do not.
>
> …

[233] Ex. AG-1.59.

[234] 8 Tr 2518-19.

Q Do you know what percentage of that money would go to new technology?

A By technology, are you talking specifically hardware?

Q Yes, I guess. You know, you said some of the money would go to salaries, but then you said not all of it. Some of it would go to technology, and I believe you said hardware, so I was trying to follow up on that portion.

A Each one of the initiatives of the 39 initiatives listed here would have a different mix, so I can't reliably state how much it would total.

Q What do you mean by different mix?

A So for example, if we were doing – I'll just pick some things off the list here. We were doing Chatbots for Move In Move Out, or we were doing drones, each one of those are small projects. They would have a different mix of software and hardware. In other words, proportions.

Q Sure. But the $8 million is a total, right, for this Applied Innovation program?

A It is.

Q So you're not certain what percentage of that for the entire program would go to hardware versus software?

A No.[235]

That exchange makes it clear that this entire program has not been well-thought out by DTE and that the Company is also uncertain and confused about where the $8 million would be going.

The AG continues to argue that this program is not well-defined or adequately supported such that spending millions on it is reasonable or prudent. In Case No. U-20162 the Commission rejected spending of $6.6 million in this project,

[235] 8 Tr 2519-21.

on the recommendation of Staff, because of a lack of clarity surrounding the project. After considering all of Mr. Griffin's direct and rebuttal testimony and his answers on cross-examination in this case, the program definition is still unclear and just as speculative as it was in the last rate case and the Company did not provide any details as to where the $8 million would go or how that would relate to these 39 nebulous "innovation initiatives." Accordingly, DTE's request should be denied.

Summary of the AG Disallowed Capital Expenditures

The following table is a summary of the Attorney General's capital expenditure recommendations:

Summary of AG Disallowed Capital Expenditures		Amount (millions)
Contingent Capital Expenditures	$	17.7
Distribution Operations		
Emergent Replacement Programs		44.6
Customer Connections, Relocations, Other		27.4
Strategic Capital Programs		182.3
Power Generation		
Routine Projects		43.0
Non-Routine Projects		40.8
Information Technology		
Major Projects		54.9
Incentive Compensation		
Capitalized Amount		44.4
Total	**$**	**455.1**

Accordingly, the Attorney General recommends that the Commission reduce the Company's proposed capital expenditures and deferred costs by $455.1 million and average rate base by $420.8 million, including working capital adjustments discussed below. Exhibit AG-1.11 provides additional details and calculations of these amounts.

V. WORKING CAPITAL ADJUSTMENTS

The AG disagrees with DTE's proposed level of working capital of $1.462 billion. The AG proposes that the level of working capital in this case be reduced by $74.3 million, to $1.388 billion, to reflect (1) the exclusion of $68.0 million of Accounts Receivable-REF Companies; (2) a $2.0 million correction to Accounts Payable-Associated Companies; and (3) reductions to the levels of Cash ($2.1 million) as well as Materials and Supplies ($2.0 million).

First, regarding Accounts Receivable from the REF Companies, in her response to Staff discovery request JSG 1.1, Company witness Uzenski stated that the Company should have excluded $68.0 million related to these receivable accounts. The Company erroneously included the balance related to these accounts receivable from 2018. Business dealings with the associated companies were discontinued in 2018. As such, the receivable amounts will not be a working capital factor in the projected test year.

Second, regarding Accounts Payable to Associated Companies, in response to Staff discovery request TGW 2.2, witness Uzenski confirmed that this balance sheet item contained a transposition error that caused a $2.0 million overstatement of working capital.

Third, the balances for Cash, as well as Materials & Supplies, included by the Company in its working capital estimate were based upon the historic year end level at December 31, 2018 and not the average historical period balances. It is more appropriate and common practice to use an average balance over the historical period and not a balance at a moment in time. As such, the AG proposes reducing the level of Cash by $2.1 million and the level of Materials & Supplies by $2.0 million.

The items discussed above result in a $74.0 million reduction of the Company's working capital estimate for the projected test year. Exhibit AG-1.15 shows the calculations to arrive at this adjustment amount.

VI. COST OF CAPITAL

Recommended Capital Structure

The AG's recommended capital structure is shown on page 1 of Exhibit AG-1.16. The first 3 lines of the exhibit under the Capital Structure heading show the projected long-term debt and common equity permanent capital of the Company for the test period ending April 2020. The permanent capital balances in this exhibit reflect a 50% long term debt and 50% common equity capital, which are the same ratios proposed by the Company in Exhibit A-14, Schedule D1. These capital structure ratios also reflect the capital percentages approved by the Commission in Case No. U-20162, the Company's previous general rate case.

Short-Term Debt Balance

The AG proposes increasing the $219.9 million short-term debt amount proposed by the Company to $337.2 million to match the amount of short-term debt shown in the 2018 historical year. The increase in short-term debt of $117.3 million in the capital structure would then be offset with an equal reduction in common equity and long-term debt.

As shown on page 2 of Exhibit AG-1.16, the Company has used progressively greater amounts of short-term debt during the 2016 to 2018 timeframe. This is to be expected as DTEE grows its business and requires higher amounts of short-term debt to meet its short-term capital needs. Although the Company continues to propose smaller amounts of short-term debt in its rate case filings (at least since U-18014), actual results since 2016 show that short-term debt has continued to increase over the past three years. Therefore, using the same amount of short-term debt used by the Company in 2018 for the projected test year is a reasonable assumption.

The additional $117.3 million of short-term debt instead of more common equity and long-term debt, which have a higher cost, decreases the revenue requirement by approximately $7.0 million.[236] The AG argues that there is no need to burden customers with this additional cost, given the Company's historical use of higher levels of short-term debt and especially after the Company increased the size of its short-term borrowing facilities.[237] Accordingly, the Commission should reject DTE's proposed capital structure with the lower short-term debt and instead adopt the capital structure proposed in Exhibit AG-1.16.

Return on Equity and Overall Return on Capital

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[236] 9 Tr 3011.

[237] 9 Tr 3010-11.

As shown in Exhibit AG-1.16 and based on the work of Mr. Coppola, the Attorney General recommends an overall return on capital of 5.23%, which includes a return on common equity of 9.25%. For Long Term Debt, Mr. Coppola utilized the 4.31% rate determined by Mr. Solomon.[238] For Short Term Debt and Deferred Taxes, Mr. Coppola utilized the cost rates recommended by Company witness Solomon and for JDITC, he utilized the long-term debt and common equity rates applicable to this case.[239]

In his direct testimony, Mr. Coppola explained the development of the overall cost of capital that is included in Exhibit AG-1.16.

> To develop the overall cost of capital on line 11, column (f), I have first developed the percentage weighting of each capital component in column (d) by dividing the individual capital balances in column (b) by the total of all capital components in that column. Next, I have multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 5.23%.
>
> Regarding the pretax weighted cost of capital on line 11, column (h), I have multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income taxes paid by the Company for calculation of the pretax weighted cost of 6.46% in column (h).[240]

Accordingly, the AG recommends that the Commission set the overall cost of capital at 5.23%.

Cost of Common Equity

[238] 9 TR 3012.

[239] 9 TR 3012.

[240] 9 TR 3012-13.

In his direct testimony, Mr. Coppola discusses at length his development and determination of the cost of common equity for the Company.[241] This area is one that the Commission has addressed extensively in all recent rate cases.

After discussing the general principals that he considered in determining the cost of common equity for the Company, specifically the principles of the Hope and Bluefield cases,[242] Mr. Coppola discusses his development of the cost of equity in Exhibit AG-1.17.[243] The AG incorporates all of that discussion here by reference.

Mr. Coppola then moves on to discuss the development of his proxy group of peer companies:

> I started with the 38 electric utility companies followed by the Value Line Investment Survey. From this group of companies, I removed seven companies, such as Duke, Exelon and Southern Company, due to their considerably larger size. I also removed four companies with annual revenues of $1.0 billion or less. Next, I removed two companies whose dividends are not growing. Finally, I removed: (a) five companies who were recently involved in mergers or acquisitions; (b) two companies with large foreign investments; (c) three companies whose earnings declined significantly in 2017; (d) Edison International due to the California wildfire liability risk, and (e) DTE Energy. Exhibit AG-1.22 shows the initial group of electric utilities from Value Line and the process of removing certain companies that are not appropriate comparable companies to arrive at the proposed peer group.[244]

The result of Mr. Coppola's work is a proxy group of eighteen companies shown in Exhibit AG-1.18, all of which are of comparable size and business profile and have growing earnings and dividends.

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[241] 9 TR 3013-15.

[242] 9 Tr 3013.

[243] 9 Tr 3014.

[244] 9 Tr 3014-15.

Mr. Coppola's group of 18 peer companies differs from the Company's peer group. The Company itself developed two peer groups of companies.[245] The larger, or broader, peer group has 26 companies.[246] Additionally, the Company selected a smaller peer group of 11 companies consisting of gas distribution and water utility companies.[247]

The Company's broader peer group of 26 companies, presented by witness Dr. Bente Villadsen, includes 14 of the companies in Mr. Coppola's peer group, plus: (a) six companies Mr. Coppola eliminated due to size considerations, (b) PPL, Consolidated Edison, and Entergy, all of whom experienced a significant drop in earnings in 2017, (c) Avangrid (with no dividend growth), Edison International (which has wildfire risk and thus dividend risk), Southern Company (which is facing major challenges constructing nuclear power facilities, and (d) DTE Energy.[248]

While the Company's broader peer group is too large and includes numerous utilities that are not comparable to DTE Electric, Dr. Villadsen's limited peer group of eleven companies consists of four water companies and seven natural gas companies, many of which have revenues much lower than DTEE, making them an inappropriate comparison and making the small peer group as a whole very inapt.

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[245] 9 TR 3015.

[246] 9 TR 3015.

[247] 9 TR 3015.

[248] 9 TR 3016.

There are other specific problems with the inclusion of water and natural gas utilities in a peer group for an electric utility. First, the water industry is in a state of consolidation. American Water Works, the largest water company selected by witness Villadsen, is a well-known business consolidator with its earnings growth highly dependent on achieving cost synergies by absorbing smaller companies.[249] According to Value Line, American Water Works is expected to achieve long-term earnings growth of 9.5%, primarily driven by acquisitions.[250]

Some of the natural gas companies chosen by witness Villadsen have substantial non-utility businesses. In particular, Chesapeake Utilities has 55% of its revenues from unregulated businesses, such as propane, natural gas marketing and midstream services. In its analysis of the company, Value Line states that Chesapeake Utilities is expected to grow earnings at a 9% rate through 2024 with most of the growth coming from the non-utility part of the business.

Although at a high level there may appear to be some similarities between electric utilities, natural gas, and water utilities, there are more significant differences than similarities. Electric utilities are typically integrated companies with generation and distribution, while natural gas and water utilities are primarily distribution companies. Electric utilities also tend to be much larger companies with larger market capitalization, and therefore easier access to capital, which lowers their cost of capital. Additionally, electric utilities face more

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[249] 9 Tr 3016-17.

[250] Ex. AG-1.24.

environmental regulation than natural gas and water utilities due to emissions from power generation. These differences more than overcome any superficial similarities that witness Villadsen and DTE may perceive.

Both DTE's larger and smaller peer group suffer from significant shortcomings, which renders them unacceptable. With regard to the Company's proposed electric peer group, it contains four electric utilities that are very small in size. The small size and market capitalization of these companies makes the trading of their common stock and public debt less liquid, increasing the cost of capital. Additionally, two of the other companies included in witness Villadsen's electric peer group are Southern Company and Edison International. Southern Company continues to face financial challenges with the construction of two nuclear plants and has been selling assets to pay for cost overruns. The risk profile of this company is not comparable to DTE Electric or other utilities in the peer group. Regarding Edison International, the company reported in its Form 10K filed with the Securities and Exchange Commission that it set up a reserve in the fourth quarter of 2018 of $1.8 billion after-tax associated with wildfire risks prior 2019. Wildfires were a major factor that forced Pacific Gas & Electric into bankruptcy. For these and other reasons discussed above, this electric peer group is not an appropriately comparable group of utility companies and should be disregarded.

With regard to the alternative peer group of natural gas and water utilities, this peer group veers off even further from a truly comparable group of companies as discussed earlier. Smaller size companies in different businesses in natural gas and water distribution are not comparable to the electric business.

For the above reasons, the AG does not believe that the Company's peer groups are appropriate and recommends that the Commission reject the Company's peer groups.

Methodology Used to Develop Cost of Common Equity

In his direct testimony, Mr. Coppola uses three approaches, along with the principals of *Hope* and *Bluefield*, to determine an appropriate cost of equity in this case. Mr. Coppola use the Discounted Cash Flow (DCF) Approach, the Capital Asset Pricing Model (CAPM) Approach, and the Utility Risk Premium Approach. Not only have these methodologies been accepted by the Commission in prior cases, these methodologies are generally accepted by regulatory commissions in other jurisdictions around the country. In his testimony Mr. Coppola discussed each of these approaches and explained how they differentiate from the approaches used by Dr. Villadsen.

As the topic of an appropriate ROE is one that has been discussed extensively in previous cases, and as the parties' specific positions are well established, this brief attempts to streamline the discussion and argument and rely primarily on Mr. Coppola's testimony for support. A brief overview of the three approaches used by Mr. Coppola will be provided, along with a synopsis of the AG's 9.25% recommendation.

Discounted Cash Flow Approach

Mr. Coppola's DCF approach is summarized in Exhibit AG-1.18 and on pages 67 and 68 of his direct testimony and results in an ROE of 8.31% for the proxy group. DTE presents "simple" DCF study results of 9.9% for the electric peer group and a 11.7% for her water/natural gas peer group, both of which are shown on page 56 of witness Villadsen's testimony.

DTE's methodology to arrive at its "Simple" DCF results relies upon a novel approach that is not used by almost any commission in the country. Witness Villadsen uses the After-Tax Weighted Cost of Capital (ATWACC) approach that the Company has advocated in several of its recent rate cases.[251] As the AG has noted in previous cases, DTE's approach starts with a normal DCF analysis and runs the results through an ATWACC process to derive a higher cost of common equity. DTE's process is further explained on page 69 of Mr. Coppola's direct testimony.[252]

The ATWACC approach produces skewed, artificially inflated results due to the high stock market to book ratios in the utility industry as a result of low interest rates and other factors.[253] This is a major flaw of the ATWACC approach that, if embraced by regulatory commissions, would lead to higher inflated ROEs awarded in rate cases. In this case, the Commission should recognize the inherent circularity of the ATWACC process. For example, if the ATWACC approach was to

[251] 9 Tr 3021.

[252] 9 Tr 3022.

[253] 9 Tr 3022.

become universally embraced by regulatory commissions, the ROEs awarded in regulatory proceedings would increase. These inflated ROEs would result in higher utility earnings, higher stock prices, and higher market to book ratios for utility common stocks. The subsequent calculated ROEs in new rate cases under the ATWACC method would then produce even higher awarded ROEs because the ATWACC would use the higher stock market equity capitalization.

It is likely because of this cost-inflating circularity and the complexity of the methodology that the ATWACC approach has not been embraced in the utility industry. In fact, DTE witnesses in prior rate cases have been able to cite only a handful of instances where it has been used. These instances pertain to (1) property taxation disputes in Colorado; (2) Florida's regulation of small water companies; (3) a valuation dispute before the FERC; and (4) revenue adequacy hearings for railroads, as well as a revenue adequacy hearing involving Alabama Power related to a special customer rate. There are no known cases where a state regulatory commission in the United States has endorsed the ATWACC approach in setting the cost of common equity in a general rate case proceeding. Therefore, the Commission should disregard the ATWACC approach to calculating the DCF cost of common equity.

Finally, Mr. Coppola discusses the results of the DCF analysis that he performed:

> The DCF analysis relies upon financial market information for the dividend yield portion of the equation. However, it also relies upon judgments of growth prospects of security analysts which may or may not be consistent with the beliefs of investors. I will point out that the forecasted growth rates for the

> proxy group include some high growth rates, which in some cases are as high as 8.5%. These high growth rates appear to be the result of a temporary rebound in earnings from a low point in recent years. While these earnings may materialize in the short term, such high rates are not sustainable long-term growth rates for electric utilities given that customer and revenue growth continues to be barely in low single digits. As such, the results of the DCF analysis in some cases reflect a return on equity rate that is somewhat higher than what investors currently expect in the long term. Nevertheless, I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other approaches to determining the cost of common equity.[254]

Capital Asset Pricing Model

Exhibit AG-1.19 and Mr. Coppola's direct testimony at pages 72-73 explain the results of the CAPM approach.[255] Using this CAPM approach, Mr. Coppola calculates an ROE rate of 7.27% for the proxy group average.[256] Mr. Coppola then comments on DTE witness Vilbert's calculations of CAPM and explains the problems with Dr. Vilbert's analysis.[257] As discussed, DTE's CAPM and ECAPM results have all been determined using the ATWACC process, which as has been previously noted leads to inflated and erroneous results.[258] The table provided on page 74 of Mr. Coppola's testimony reconciles the differences between DTE's approach and the AG's approach and points out that DTE proposes additional upward adjustments to its CAPM results which are subjective, unconventional, and unsupported.

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[254] 9 Tr 3024.

[255] 9 Tr 3025-26.

[256] 9 Tr 3026.

[257] 9 Tr 3026-28.

[258] 9 Tr 3026.

DTE's various methods used to calculate the cost of equity capital are inventive, highly unconventional, not generally accepted, and are based in part upon DTE's own opinion that risk levels have permanently risen since the 2007-2008 financial crisis. Based upon that and the reasons presented in Mr. Coppola's testimony, the Commission should reject these alternative approaches, which clearly reflect an attempt by DTE and Dr. Villadsen to inflate the Company's true cost of common equity.

Finally, Mr. Coppola assessed the CAPM approach, finding that it can be useful in assessing the relative risk of different stocks or portfolios of stocks.[259] However, he concluded that the CAPM approach should be given much less weight than the DCF approach in determining the cost of common equity, because the key issue with CAPM is that is assumes that the entire risk of a stock can be measured by the "Beta" component and as such the only risk an investor faces is created by fluctuations in the overall market.[260] In actuality, investors take into consideration company-specific factors in assessing the risk of each particular security.

Utility Risk Premium Model

Exhibit AG-1.20 and Mr. Coppola's direct testimony at page 76 explains the results of the Utility Risk Premium approach.[261] Using this Utility Risk Premium approach results in an ROE rate of 9.08%.[262] In this context, Mr. Coppola analyzed

[259] 9 Tr 3028.

[260] 9 Tr 3028-29.

[261] 9 Tr 3029.

[262] 9 Tr 3029.

the economic and interest rate environment in recent years for DTE and explained that the Michigan economy has substantially recovered from the most recent recession and interest rates are stable at lower levels.[263] These factors have placed DTE in a better position with respect to sales levels, interest rates, and uncollectible amounts.[264] In addition, DTE's access to capital is strong as witnessed by its issuance in February 2019 of $650 million of new 30-year long-term debt at a rate of 3.95%.[265] The Company's senior secured debt ratings are A/Aa3 and its commercial paper program is rated P-1 (highest) by Moody's.[266] Also, the Company's parent DTE Energy accessed the capital markets in August 2019 issuing approximately $1.5 billion of new long-term debt with maturities of three to ten years with rates in the 2.5% to 3.4% range.[267]

For its part, DTE does not provide any utility risk premium analysis. Witness Villadsen does provide testimony on "risk premium model estimates." Beginning on page 57 of her testimony, Witness Villadsen states that she compared the authorized ROEs from electric utility rate case decisions from 1990 to 2018 to 20-year U.S. Treasury bonds. According to her testimony, she performed a regression analysis to the data and found a strong relationship between ROEs and interest rates. She also observed that ROE rates have fallen more slowly than

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[263] 9 Tr 3031-32.

[264] 9 Tr 3031-32.

[265] 9 Tr 3031.

[266] 9 Tr 3031.

[267] 9 Tr 3031.

Treasury bond interest rates. Based on her model results, she concluded that an ROE of 10.2% to 10.3% for a vertically integrated electric utility would be appropriate, based on 20-year U.S. Treasury rates of 3.50% to 3.75%. Interestingly, the current interest rate for 20-year U.S. Treasury bonds is 2.1%, or about 1.6 percentage points below her assumed rates. Using the current 20-year U.S. Treasury rate would result in a proposed ROE of approximately 8.6%.[268]

What is troubling about this analysis is that it lacks any comparison of actual returns achieved on utility common stocks (via price appreciation and dividends) to treasury bonds, and suggests that treasury bond yields are the primary driver in ROE decisions by regulators. This analysis has no validity as a tool to determine the ROE to be established in rate proceedings. Regulators approach the serious business of establishing an ROE based on many factors and often exercise "gradualism" in the process as well. Accordingly, the Commission should give this analysis no weight in this case.

Recent ROE Rates from other Commissions

Mr. Coppola also examined ROEs granted by other regulatory commissions around the country in 2018 and 2019. He explained:

> Since 1990, return on equity rates, granted by regulatory commissions in the U.S., have been in a steady decline from over 12.7% in 1990 to approximately 9.6% in the January 2018 through 2019 period.
>
> Exhibit AG-1.21 shows the more recent ROE rates granted by state regulatory commissions for electric utilities during 2018 and 2019 and published by Regulatory Research Associates, a respected and independent regulatory research firm. More than 80% of electric

[268] 9 Tr 3030.

> decisions rendered involved ROE rates averaging 9.5% during this eighteen-month time frame. With declining interest rates in the near term, it is likely that ROE rates granted by regulatory commissions will continue to decline.
>
> Page 1 of Exhibit AG-1.21 shows the most recent ROEs assigned to the peer group companies through June 2019. The average ROE rate for this group is 9.58%. Recent ROE decisions for the group have trended down, with rate decisions as low as 8.69 in Illinois. The large group of utilities shown on pages 2 and 3 of this exhibit shows similar trends with ROE rates well below 10% with only few exceptions. These pages also include information regarding debt financing subsequent to the rate orders. It is clear from this information that the capital markets have continued to provide debt capital at competitive interest rates to electric utilities with authorized ROEs well below 10%.[269]

As this above analysis demonstrates, ROEs across the nation are on a declining trend and are predominantly below 10%. Thus, DTE's request to increase its ROE is contrary to determinations made by every other regulatory commission.

Accordingly, based on all the above, DTE's recommendation that the ROE should be increased to 10.5% is unsupportable and largely based on unconventional methodologies applied to CAPM, DCF, and Utility Risk Premium cost of equity calculations. As contained in the analysis by Mr. Coppola, the results of the DCF analysis, CAPM analysis, and Risk Premium Approach, together with lower interest rates, a better Michigan economy and a very favorable regulatory environment all point to a calculated cost of equity closer to 9%.

Conclusion

Mr. Coppola summarized his conclusions regarding the appropriate ROE in this case in Exhibit AG-1.17. The range of returns for the industry peer groups is

[269] 9 Tr 3032.

from 7.27% at the low end using the CAPM approach and 9.08% at the high end using the Utility Risk Premium approach.[270] After weighting the various approaches, Mr. Coppola calculated a weighted return on equity of 8.19% for the average industry peer group.[271] Mr. Coppola, however, explained that he is recommending a higher ROE rate of 9.25% based on a DTE Electric specific analysis:

> First, long-term interest rates are currently at a low level, and although they certainly justify ROEs well below 9.25%, they could negatively impact the long-term cost of common equity if they were to increase significantly in the coming years. As such, while the cost of common equity I have calculated is an accurate assessment of expectations for the forecasted test year, significantly higher U.S. Treasury interest rates at or above the 3.2% level assumed in this rate case analysis may produce a different result should such higher interest rates become a reality. In this regard, a potential 10% correction in utility stock prices dues to higher interest rates would produce a 0.30% to 0.40% increase in the cost of capital under the DCF approach.
>
> Second, the Company's own witness calculated the cost of common equity for the electric peer group, before being adjusted upward for the ATWACC methodology, at 8.6% under the DCF approach and at 8.2% (its highest rate) under scenario 2 of the CAPM methodology.
>
> Third, I understand that the Commission may be reluctant to set a ROE for the Company at the true cost of equity of 8.19%. Regulatory commissions around the country have granted ROEs averaging 9.5% to electric utilities during 2018 and 2019, with only few cases granted at the 10.0% level. In fact, approximately 50% of the reported ROE decisions in electric utility rate cases reported by "Regulatory Focus" during this time frame are well below the average rate of 9.5%. Therefore, my recommended ROE rate of 9.25% in this case is reasonable and fair, if not generous, as a gradual transition to the true cost of equity.[272]

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[270] 9 Tr 3033.

[271] 9 Tr 3033.

[272] 9 Tr 3034.

As noted above, Mr. Coppola developed, and the Attorney General recommends, an ROE of 9.25% in this case as a reasonable and fair, if not generous, and gradual transition to the true cost of equity.

The cost of equity for DTE Electric is 8.19% and continues to decline for all utility companies. In conjunction with the recession of 2008-2009, the Federal Reserve reduced interest rates significantly to spur economic activity. The result has been a long-protracted period of low interest rates and low inflation, which has provided low cost of capital and has boosted the U.S. economy. While some financial experts have argued that the Federal Reserve easing of interest rates was a temporary phenomenon, it is now in its 10th year and continuing.

Therefore, low interest rates are no longer temporary. They persist and need to be fully reflected in the determination of return on equity rates. Interest rates have a direct correlation to the cost of common equity because those two sources of capital compete for investors' funds. The long-term cost of debt and equity capital has declined significantly since 2010 and must be recognized by regulatory commissions in setting appropriate ROE rates. ROE rates currently granted by many regulatory commissions are still significantly above the true cost of equity for those utilities and they unnecessarily increase customer rates.

The Commission should not be concerned that establishing an authorized ROE of 9.25% in this case will lead to the impairment of the Company's ability to access capital markets. In his testimony Mr. Coppola explains:

> In recent general rate case proceedings, certain rate case applicants have raised arguments that they should receive a ROE of 10% or higher to ensure the financial soundness of the business and to maintain its strong ability to attract capital in addition to being compensated for risk. Pages 2 and 3 of Exhibit AG-1.21 show several utilities that have accessed the capital markets at competitive interest rates since receiving a ROE near or below the average rate of 9.50%.
>
> Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs below 10%. On the contrary, stock investors continue to migrate to utility stocks, recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-1.23 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past few years reflecting ROEs as low as 8.69%. Yet this group of companies has an average Market to Book common equity value ratio of nearly 2.3 times.
>
> This information is provided to dispel the myth that the Company must receive an ROE at or above 10% or it will face dire consequences in the financial markets.
>
> The fact that the Company needs to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to DTE Electric. Other electric and gas utilities face the same issues and are able to raise capital with ROEs well below 10.0%.[273]

Finally, Mr. Coppola also calculated that if the Commission grants a 9.9% ROE in this case versus his recommended 9.25% ROE, the Commission is adding an additional $61.6 million in costs to customers annually.[274] Accordingly, the Attorney General recommends a 9.25% ROE in this case.

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[273] 9 Tr 3036.

[274] 9 Tr 3036.

VII. DEPRECIATION EXPENSE

The AG proposes an adjustment to depreciation expense for the projected test year. As a result of the reductions in capital expenditures proposed above and the impact on capital additions included in rate base, Mr. Coppola calculated a reduction in depreciation expense of $16,987,000. The calculation of this amount is shown in Exhibit AG-1.11 and is based on the same depreciation rates used by the Company on page 2 of Exhibit A-13, Schedule C6. The AG recommends that the Commission reduce the depreciation expense proposed by the Company for the projected test year by $16,987,000.

VIII. EXCESS DEFERRED TAXES

DTEE was one of a few utilities under the jurisdiction of the Commission that did not file a separate case for the determination of Calculation C issues and the passthrough of excess accumulated deferred federal income taxes (ADFIT) to customers. Instead, only some issues, such as the inclusion of the amortization of the excess ADFIT were addressed in Case No. U-20162 and in this rate case. However, unlike the Calculation C cases for other utilities, the Commission has not addressed the procedures for reconciliation and reporting of the excess ADFIT over future years.

The AG argues that DTE should be required to reconcile the actual amount of excess deferred tax amortization to the amount estimated in setting base rates and report those differences to the Commission. The annual amortization amount of the excess deferred taxes for the protected property portion is not a fixed straight-line annual amortization. The amortization amount changes from year to year as the timing differences of the underlying depreciable assets vary. It is also likely that retirements and other adjustments to plant and non-plant assets and liabilities will change the annual amortization of both protected and non-protected excess deferred assets and liabilities.

Therefore, the net excess deferred tax amortization amounts assumed in base rates are not likely to match the actual annual amortization amounts. To ensure that customers receive the actual excess deferred tax savings owed to them, the AG recommends that the Commission order the Company to establish a regulatory deferred asset or liability account to record the annual differences between the excess deferred taxes passed through to customers versus the actual amortization amounts for each of the three categories of excess deferred taxes. The differences in the regulatory liability or asset account will be reflected in customer rates over a period of time established by the Commission in the Company's next general rate case. The Commission should order the Company to begin this reconciliation with the first year's amortization of the excess ADFIT.

In addition, the Commission should direct the Company to file an annual letter to this case docket by March 31 of each year until the excess deferred taxes are completely refunded to customers. For each of the three categories of excess deferred taxes, the letter should include: (1) the beginning refundable balance, (2) the yearly passthrough amount to customers, (3) the over/under regulatory asset/liability the Company has recorded, which is calculated as the difference between the actual amount of excess deferred taxes in a given year and the estimated amount included in rates, and (4) the ending refundable balance.

Deferred taxes are considered zero cost capital and are normally included in the capital structure as a source of capital in the calculation of the overall cost of capital. Before the enactment of the TCJA, all deferred taxes at the federal tax rate of 35%, as well as comparable state deferred taxes, were included in the capital structure. Although a portion of the deferred taxes representing the difference in the federal tax rate from 35% to 21% are now refundable to customers, these amounts are still deferred taxes that have not yet been refunded and they properly belong with other deferred taxes in the capital structure at zero cost.

Therefore, the AG recommends that the remaining excess deferred tax liabilities and assets for the projected test year that are not yet passed through to customers be included with other deferred income taxes in the capital structure in future general rate cases. From DTEE's filing in this rate case, the Company has taken this same approach. However, the Commission order in this rate case should clearly specify that requirement.

IX. ADJUSTMENTS TO REVENUE DEFICIENCY

Exhibit AG-1.42 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $41.1 million, which is a reduction of $309.6 million from the Company's requested level of $350.7 million. The AG recommends that the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $41.1 million.

Dr. David Dismukes

Dr. Dismukes is the third of the AG's expert witnesses in this case. His testimony focuses on DTE's class cost of service study (CCOSS) and revenue distribution, and he makes certain recommendations which the Attorney General adopts and advocates for.

Conclusions and Recommendations

The following are Dr. Dismukes' conclusions and recommendations, which will be discussed further below.

With regard to DTE's CCOSS, he recommends that the Commission utilize a set of alternative CCOSS methodologies that include: (1) use of a 4CP 50-0-50 cost allocation method for classifying and allocating costs associated with production plant facilities; (2) the use of a 12CP 100-0-0 cost allocation method for classifying and allocating costs associated with sub-transmission plant facilities, and (3) a non-coincident peak (NCP) cost allocation of costs associated with secondary-distribution plant facilities.

With regard to revenue distribution, he recommends that the Commission adopt a revenue distribution that reflects his alternative CCOSS recommendations. The ultimate revenue distribution effects of those changes will depend on the Commission's adopted revenue requirement for the Company, but based on the Company's proposed revenue requirement, the changes discussed earlier would result in the residential customer class receiving a 5.3 percent increase in rates, secondary customers receiving a 10.3 percent increase in rates, while primary customers would receive a 7.0 percent increase in rates.[275]

Finally, if the Commission declines to accept his proposed CCOSS changes, Dr. Dismukes recommends that the Commission limit any rate increase to the residential customer class to 1.15 times the overall system average increase. In the case of the Company's proposed revenue requirement increase, which recommends a 7.1 percent overall system average increase, this recommendation would limit any proposed increase to the residential customer class to 8.2 percent. Revenue increases displaced by this proposal would be allocated on an equal proportionate basis, based on cost of service increase to remaining classes.

Analysis and Argument

As highlighted in Dr. Dismukes' testimony, the AG's concern is that DTE's recent string of enormous rate increases has disproportionately fallen on DTE's residential and other smaller usage customers, when compared to primary-voltage and other high load factor customers.[276] Dr. Dismukes' research and analysis presented in his direct and rebuttal testimony show that under DTE's current CCOSS, small usage customers are subsidizing higher load factor customers.

The revenues collected from residential customers have increased by 34.9% since Case No. U-15244.[277] Revenues from primary-voltage customers, on the other

[275] Ex. AG-2.12.

[276] 9 Tr 2836.

[277] 9 Tr 2836.

hand, have decreased by 24.5 percent over the same time period.[278] This trend of rate increases being biased towards smaller usage customers will continue if the Company's proposals are accepted in full by the Commission in this proceeding. For example, the Company's current proposal includes a 9.1 percent increase to residential rates, and only a 2.9 percent increase to primary-voltage customers.

The large rate increases for residential customers relative to larger usage/higher load factor customers are mainly a function of the Company's proposed CCOSS methods. Section 11 of Act 286 took effect January 1, 2009[279] and proposed a cost allocation method for production plant facilities beginning with Case No. U-15768 in 2010.[280] Section 11 of Act 286 also required the Commission adopt cost-of-service based rates. These new, legislatively-mandated cost allocation methods resulted in more costs being allocated to residential customers relative to higher load factor customers. The methodology adopted as a result of Act 286 was subsequently changed by the Commission in Case No. U-17689 in 2015 in order to "better recognize the value of capacity in [DTE's] production system."[281] This new cost allocation method, referred to as 4CP 75-0-25, was adopted beginning with

[278] 9 Tr 2836.

[279] 2008 PA 286 § 11(1).

[280] In the Matter of the Application of The Detroit Edison Company for Authority to Increase its Rates and Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy; Case No. U-15768 et al.; Opinion and Order, pp 1-2.

[281] In the Matter, on the Commission's Own Motion to Commence a Proceeding to Implement the Provision of Public Act 169 of 2014; MCL 460.11(3) et seq., with Regards to DTE Electric Company; Case No. U17689; Opinion and Order, p 20.

Case No. U-17767 in 2015,[282] and later referenced as a baseline method in Act 341 of 2016.[283] While the method is discussed in depth later, it disproportionately allocates a large share of its overall costs on a method that favors higher load-factor customer classes at the expense of low load-factor classes.

<u>Class Cost of Service Study (CCOSS) General Overview</u>

A CCOSS is a method by which utility costs and revenues are reconciled across different customer classes. The goal of a CCOSS is to determine the cost of providing service to an individual customer class and the revenue contribution each class should make to cover those costs. The results of these studies produce a rate of return and revenue requirement. The rate of return and revenue requirement can be used as a tool in developing the relative revenue responsibility and rates for each rate class within a specific jurisdiction.[284]

Typically, a CCOSS is prepared by defining a set of cost information, and then (1) "functionalizing" the cost information; (2) "classifying" the cost information; and (3) "allocating" the cost information. The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The next step of the process "classifies" each of these respective costs into a unique "type" of cost,

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[282] In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-17767; Order pp 112-13.

[283] 2016 PA 341 § 11(1).

[284] 9 Tr 2838.

including those that are either demand-related,[285] commodity-related,[286] or customer-related.[287] The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class as appropriate.

This process is relatively complex. Some costs can be clearly identified and directly assigned to a function or category, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations.[288] It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the CCOSS, and the implications both have in setting fair, just, and reasonable rates.

The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a rate case. While the latter two activities are dedicated to determining how much revenue will be recovered through rates, the CCOSS process determines *how* those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various

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[285] 9 Tr 2838.

[286] 9 Tr 2838-39.

[287] 9 Tr 2839.

[288] 9 Tr 2839.

CCOSS results often rests with determining whether costs (revenue requirements) will be recovered by the relative customer share of each class, the peak load contributions of each customer class, or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily skewed toward customer and peak considerations, for instance, can tend to shift costs more than proportionally to relatively lower load-factor customers, such as residential and small commercial customers. These approaches can also fail to capture the service being provided by the utility (i.e., electric service in this case), and how the value of that service varies by the amount purchased by different customer classes.[289]

Overview of DTE's CCOSS

DTE states that its objective is for its CCOSS to apportion all costs required to serve customers among each customer class in a fair and equitable manner, defined as a manner which best reflects the engineering and operating characteristics of the electric utility system.[290] To accomplish this, DTE functionalized all costs in the cost study as either power supply (combining the elements of the traditional production and transmission functions) or distribution.[291]

[289] 9 Tr 2840-41.

[290] Direct Testimony of Thomas W. Lacey, p 6.

[291] Direct Testimony of Thomas W. Lacey, p 7.

DTE uses a variety of "demand allocators" within its CCOSS to allocate the different classified costs in its study. To allocate production plant costs classified as demand-related, the Company uses what it refers to as a "4CP 75-0-25" cost allocation method.[292] This is a hybrid allocation factor combining two separate component calculations through a weighted average. The first component is based on an examination of each rate class' contribution to the Company's average four monthly coincident peaks (4CP) and this average receives a 75% weight. The second component of this allocator uses a 25% weight of each rate class' contribution to DTE's annual energy requirement.[293]

To allocate transmission plant costs classified as demand-related, the Company uses what it refers to as a "12CP 100-0-0" cost allocation method, which is based on an examination of each rate class' contribution to the Company's average twelve monthly CP (12CP).[294] For lower-voltage transmission facilities classified as demand-related, the Company uses each rate class' relative non-coincident peak (NCP) demand to allocate costs associated with sub-transmission and primary-voltage distribution facilities.[295] The Company uses several separate allocation factors calculated using this generalized approach, accounting for different class loss factors and class uses at different voltage levels on the Company's system.[296]

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[292] Direct Testimony of Thomas W. Lacey, p 10.

[293] Direct Testimony of Thomas W. Lacey, p 10.

[294] Direct Testimony of Thomas W. Lacey, p 10.

[295] 9 Tr 2842.

[296] For example, sub-transmission rate classes are not assigned any portion of distribution-specific costs, while primary voltage distribution rate classes are not

Lastly, the Company uses a summation of each individual customer maximum demand within a rate class to allocate secondary-voltage distribution facility costs classified as demand-related.[297]

As discussed in Dr. Dismukes' testimony, the AG disagrees with several of the Company's CCOSS cost allocation methods, including the: (1) classification of production plant; (2) the sub-transmission plant demand allocator; and (3) the secondary-voltage distribution demand allocation based on a summation of each individual customer maximum demand.

(1) Classification of Production Plant

As noted, DTE's CCOSS employs a 4CP 75-0-25 cost allocation method for production plant costs. Use of this method appears to stem from Section 11 of Act 286, often referred to as the "de-skewing" provision,[298] which required the Commission to phase in electric rates set equal to cost of service over a five-year period.[299] In response to Section 11, in Case No. U-17689 the Commission first approved the current 4CP 75-0-25 allocation method. In Case No. U-17689, the Company's initial CCOSS proposal utilized a 100% 4CP cost allocation methodology

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assigned any portion of secondary-specific distribution costs as these customers bypass these systems. For a general diagram of DTE's system operations, see Ex. A-16.

[297] 9 Tr 2842.

[298] Babcock, Lisa and Rodger Kershner (January 2011), Changes in the Law Governing Public Utilities, Michigan Bar Journal, January 2011, p 40.

[299] 2008 PA 286 § 11.

for classifying and allocating costs associated with production plant facilities,[300] thus proposing to change the demand measurement for production plant from the existing 12CP to 4CP and removing the existing energy component to the allocation factor. The Company argued that such a change was warranted since it had completed the process of de-skewing rates outlined in Section 11 of Act 286, and that future expected generation shortfall in the Lower Peninsula from generation retirements warranted the requested change.[301] The Company argued that future production plant investments would be driven by the need to meet system demand requirements during its four summer peaking months.[302]

> [a 100 percent 4CP allocation] reflects the increased emphasis on production capacity, rather than energy, which is necessary due to the need for new production capacity and the investment necessary to retrofit existing generation to meet environmental standards.[303]

Staff disagreed in part with DTE's proposal in U-17689, and the Commission agreed with Staff, stating that the Company's system included a mix of base load plants designed to provide low-cost energy to all customers and peaking plants

[300] In the Matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) et seq., with regard to DTE Electric Company; Case No. U-17689, Opinion and Order, p 3.

[301] In the Matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) et seq., with regard to DTE Electric Company; Case No. U-17689, Opinion and Order, p 3.

[302] In the Matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) et seq., with regard to DTE Electric Company; Case No. U-17689, Opinion and Order, p 4.

[303] In the Matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) et seq., with regard to DTE Electric Company; Case No. U-17689, Opinion and Order, p 4, citing DTE Electric Initial Brief, p 13.

designed to meet peak demands during summer months.[304] The Commission also accepted Staff's proposed 4CP 75-0-25 cost allocation methodology as more consistent with this understanding and thus better aligned with cost of service.[305]

The Legislature has since revisited Section 11 of Act 286, first in Public Act 169 of 2014,[306] and again in Public Act 341 of 2016 (Act 341).[307] Act 341 notably modified Section 11 to remove the Legislature's stated preference for a 12CP 50-25-25 allocation for production-related costs, instead advocating for the '75-0-25' cost allocation, but permitting the Commission to modify this cost allocation approach if it determined these approaches did not ensure appropriate cost of service-driven rates.[308] Importantly, the Legislature also granted increased flexibility to the Commission in setting cost of service-based rates, allowing for the Commission to implement rate changes over time if it determines that there is a material impact on customer rates.[309]

As discussed in Dr. Dismukes' testimony and elsewhere in this case, DTE Electric's CCOSS and the 4CP 75-0-25 allocation method is having a material

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[304] In the Matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) et seq., with regard to DTE Electric Company; Case No. U-17689, Opinion and Order, pp 21-22.

[305] In the Matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) et seq., with regard to DTE Electric Company; Case No. U-17689, Opinion and Order, p 23.

[306] 2014 PA 169 § 11.

[307] 2016 PA 341 § 11.

[308] 2016 PA 341 § 11(1); note Act 341 does not define the referenced 75-0-25 cost allocation methodology.

[309] 2016 PA 341 § 11(1).

impact on customer rates, skewing results away from actual cost of service rates and placing a higher burden on smaller usage customers. While the framework of the 4CP 75-0-25 allocation generally adheres to commonly accepted cost allocation practices, the arbitrary 75 percent demand and 25 percent energy weighting for classifications does not. It is typically accepted that the weighting between demand and energy components should be equal (i.e. 50-50) or based on the utility's system load factor.[310] This latter method weights the energy component by the utility's overall system load factor while the peak demand component is weighted by the inverse of the system load factor (i.e., 1 minus the system load factor).

A load factor is defined as the ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period.[311] The load factor is expressed as a percentage and may be derived by multiplying the megawatt hours in the period by 100 and dividing by the product of the maximum demand in megawatts and the number of hours in the period. A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently since usage is consistent and does not swing largely between average and peak periods. Conversely, systems with low load factors must maintain idle capacity in order to meet the relatively large swings in load between average and peak periods.

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[310] See, Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, pp 57-59.

[311] 9 Tr 2850.

Exhibit AG-2.3 shows DTE's system load factor for the test year using different measures of peak demand, specifically 1CP, 4CP, and 12CP. This analysis shows that the Company's system load factor ranges from 43.8 to 57.2 percent based on the measure of peak demand. However, under 4 CP, the measure of peak demand used in the current production plant allocator, results in a system load factor for the test year of 44.4 percent.

Exhibit AG-2.4 shows DTE's system load factors using 4CP for the five-year period 2014 through 2018. As can be seen from Exhibit AG-2.4, DTE's system load factors have been stable throughout the five-year period. Specifically, DTE's system load factors have consistently been in a narrow range of between 44.4 and 47.2 percent. The results of the analysis presented in Exhibit AG-2.4 imply that the current 4CP 75-0-25 cost allocation methodology is too heavily weighted towards demand considerations relative to energy when compared to the Company's actual reported data.

The Commission noted in Case No. U-17689 that electric utilities develop and operate production plant facilities around both capacity and energy requirements.[312] The analysis of DTE system load factors shows that the split between these two functional requirements is essentially equal, a finding that should be reflected in the allocation for cost of service purposes in the Company's CCOSS.

In the Company's last rate case, parties recommended that the Commission

[312] 9 Tr 2851.

review DTE's production cost allocation method in the Company's next rate case.[313] The ALJ agreed with this recommendation, noting that DTE had failed to rebut evidence that energy costs allocated through the Company's CCOSS are less than MISO Locational Marginal Prices (LMP), while allocated capacity costs are higher than estimated Cost of New Entry (CONE).[314] The Commission also agreed with this assessment and reminded parties of its previously expressed preference for the equivalent peaker cost allocation method or something similar:

> That any party proposing to revise the production cost allocation method in a future case include in its evidentiary presentation an analysis using the equivalent peaker method or an approximation for comparison purposes. On pages 52-53 of the NARUC Manual, it states that "[e]quivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generation capacity and the most cost-effective type of capacity to be added."[315]

The equivalent peaker and related base-intermediate-peak cost allocation methods are cost allocation methods that seek to determine production capacity costs based on the composition of the generation facilities being allocated. In these

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[313] These parties included MEC, NRDC, and the Sierra Club. See: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-20162; Order, p 125.

[314] In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-20162; PFD, p 228.

[315] In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-20162; Order, p 129.

allocation methods, rate base for each operating generation facility is calculated and then classified between demand and energy classifications based on the characteristics of the generation facility. Rate base associated with peaking plants are classified as 100% demand-related, while rate base of other generating units are carefully proportioned between demand and energy classifications.[316]

In past cases, the Commission has brought up the equivalent peaker cost allocation method in the context of seeking quantifiable information to address the appropriate division between demand and energy components in the allocation of production costs. An analysis of the Company's system load factor addresses this concern. In fact, Dr. Dismukes' finding of a system load factor of approximately 50% implies that the Company's system, during its all-in system peak demand events, is serving a demand wherein half of which is equivalent to the annual average load requirements placed on the system and the other half is 'peak' demand that only occurs during these peak events. In other words, during these system peak demand events, half of the load present is baseload while the other half can be considered peak load.

To better understand DTE's system and what would constitute proper cost allocation, Dr. Dismukes conducted analyses of the relative classification of individual Company generation units and those units' operations.[317] Both analyses, which are presented in Exhibit AG-2.5, examine the Company's electric generation

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[316] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, pp 52-53.

[317] 9 Tr 2854-56.

fleet on the basis of production plant in service. Most of the Company's electric generation fleet are peaking units that are constructed to serve the capacity needs of the Company's system. However, the Company's non-peaking generation fleet comprises the majority of the Company's production plant in service. The Monroe facility alone represents 40.7% of the Company's gross production plant in service. In total, 90% of the Company's production plant in service is associated with the Company's five coal facilities and the Fermi 2 nuclear facility. These analyses show a significant portion of these facilities being operated to support the provision of non-demand functions.

Exhibit AG-2.6 then compares the relative rate class allocations of a 4CP 50-0-50 cost allocation method to the current 4CP 75-0-25 cost allocation method and the 12CP 50-25-25 cost allocation method. Exhibit AG-2.6 shows that primary-voltage distribution service customers are allocated 31.4% of costs under a 4CP 50-0-50 cost allocation method, greater than the 27.9% under a 4CP 75-0-25 cost allocation method. However, it should be noted that a 4CP 50-0-50 cost allocation of production plant results in a lesser allocation of production plant costs to primary-voltage distribution service customers compared to the 12CP 50-25-25 cost allocation method, which would allocate 36.7% of production costs to primary-voltage distribution service customers.

Based on the above, the AG recommends that the Commission modify the weighting of the existing 4CP 75-0-25 cost allocation method to one that equally weights demand and energy concerns, or a 4CP 50-0-50 cost allocation methodology.

In the Company's last rate case, U-20162, the Commission found it reasonable to revisit the existing 4CP 75-0-25 cost allocation method if parties provided evidence that the existing cost allocation method results in rates that are not cost-based.[318] The AG's proposed 4CP 50-0-50 cost allocation method is based on Dr. Dismukes' analysis of what would constitute a fair and reasonable approximation of the relative cost of service. Specifically, the 4CP 50-0-50 method would make the cost allocation of the Company's production plant consistent with recent system load factors for DTE over the last five years (2014 through 2018), which have consistently ranged between 44.4 and 47.2%. Furthermore, it would make the cost allocation consistent with examinations of the relative classification of individual Company generation units.

<u>Allocation of Sub-Transmission Plant</u>

Currently, DTE allocates costs associated with its sub-transmission plant facilities on the basis of each class' NCP.[319] In testimony, Dr. Dismukes discusses the role that sub-transmission plays in electric systems, how that has changed over time to a "quasi-transmission" role, and how transmission assets are defined.[320] Exhibit AG-2.7 then presents an inventory of DTE's sub-transmission plant assets, which Dr. Dismukes compares to voltage classes found elsewhere in the United

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[318] In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority; Case No. U-20162; Order, p 129.

[319] 9 Tr 2858.

[320] 9 Tr 2858-59.

States.[321] He notes that the presence of 120 kV lines on the Company's sub-transmission system is unusual, as voltages greater than 115 kV are usually associated with bulk transmission systems,[322] which reflects the quasi-transmission role sub-transmission plays in the delivery of electric power.

Dr. Dismukes also notes that FERC has accepted NERC's bright-line rule that facilities 100 kV or higher are bulk electric systems, with the exception of defined radial facilities.[323] Therefore, the Company's 120 kV lines, which comprise approximately 1.9% of the Company's sub-transmission system by mileage, are certainly closer in characteristic to transmission systems than the Company's distribution system. The Company's 40 kV lines, which comprise more than 74.1 percent of the Company's sub-transmission system by mileage, could also be considered as close in characteristic to transmission systems as the Company's distribution system.

Based on the above and on Dr. Dismukes' analysis, the AG recommends that the Commission adopt a 12 CP 100-0-0 cost allocation methodology to allocate costs associated with sub-transmission plant facilities. This would make the allocation of sub-transmission consistent with the current allocation of transmission plant, reflecting the quasi-transmission role sub-transmission plays in the delivery of electric power. This is compared to the Company's current allocation method, which

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[321] 9 Tr 2860.

[322] MISO defines bulk electric systems as facilities "generally operated at voltages of 100 kV or higher." MISO FERC Electric Tariff (November 19, 2013), Sec. 1.B.

[323] 9 Tr 2860.

effectively treats sub-transmission as serving the same function as primary-voltage distribution plant.

Allocation of Secondary-Voltage Distribution Plant

To allocate costs associated with secondary-voltage distribution plant facilities, DTE currently uses an allocation methodology based on the summation of individual customer's peak demand requirements to allocate costs associated with secondary-voltage distribution plant facilities.[324] This is in contrast to how the Company allocates costs associated with other demand-related distribution plant facilities, which the Company allocates on the basis of class NCP.[325] In practice, the Company's proposed allocation of costs associated with secondary-voltage distribution plant facilities places a higher burden on lower load factor customer classes, such as residential customers, as it assumes that facilities must be designed to serve the maximum demand of each customer simultaneously, regardless of how customer load profiles compare to each other.

Dr. Dismukes' testimony discusses how distribution systems are designed and operated in the context of the larger electric grid and how differences in end-use load diversity impact appropriate cost allocation.[326] While DTE has not examined the diversity of loads present on its secondary-voltage distribution system, other electric utilities have conducted such analyses, which helps drive how they allocate

[324] 9 Tr 2861.

[325] 9 Tr 2861.

[326] 9 Tr 2862-63.

costs associated with secondary voltage distribution systems.[327] In Dr. Dismukes' study of other electric utilities, he notes that in 66.7% of cases the accepted CCOSS allocated costs associated with demand-related secondary-voltage distribution plant on an identical basis to costs associated with demand-related primary-voltage distribution plant assets and that in 72.2% of accepted CCOSS, the allocation of secondary-voltage distribution plant was based on identified class NCP.[328]

Accordingly, the AG recommends that the Commission allocate costs associated with demand-related secondary-voltage distribution systems based on class NCP demands. The Company's proposed allocation places too much emphasis on individual customer peak loads and fails to recognize that not all customers present on the system peak at the same time. Furthermore, allocating secondary-voltage distribution costs in a manner consistent with the allocation of primary-voltage distribution costs is consistent with how these costs are typically allocated in other jurisdictions.

<u>Summary</u>

In summary, the AG recommends that the Commission utilize a set of alternative CCOSS methodologies that include: (1) use of a 4CP 50-0-50 cost allocation method for classifying and allocating costs associated with production plant facilities; (2) the use of a 12CP 100-0-0 cost allocation method for classifying

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[327] 9 Tr 2863-64.

[328] 9 Tr 2864.

and allocating costs associated with sub-transmission plant facilities, and (3) an NCP cost allocation of costs associated with secondary-distribution plant facilities.

Use of these recommendations would change the class rates of return. Exhibit AG-2.8 contains an explanatory alternative CCOSS. Pages 1 and 2 of the exhibit show the results of the alternative CCOSS as it relates to DTE's provision of power service, while pages 3 and 4 relate the DTE's provision of distribution service. Obviously Exhibit AG-2.8 is presented for explanatory purposes only, as it is independent of the AG's and other parties' other revenue requirement adjustments. The other adjustments would need to be taken into account in determining a final alternative CCOSS. Exhibit AG-2.9 shows the results of the Company's CCOSS in this same format.

Finally, Exhibit AG-10 shows the results of the Company and the AG's explanatory alternative CCOSS as it relates to the breakout of required capacity and non-capacity revenues associated with the provision of power service.

Revenue Distribution

Revenue Distribution Policy and Process

The revenue distribution process allocates a utility's overall revenue deficiency across customer classes, which in turn is used to establish a new set of retail rates to be applied prospectively. The revenue distribution process often uses the results from the CCOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated rate of return, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The class revenue responsibilities that are finally established are then used, in conjunction with each class' billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates. Regulators often temper the revenue responsibilities assigned to various customer classes in order to meet a broad set of ratemaking policy goals, including:

- Rates should be fair, just, and reasonable, and not unduly discriminatory.
- Gradualism should be used, where possible, to protect against rate shock.
- Rate continuity should be maintained.
- Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
- Rates should be understandable to customers.

Regulators may consider some or all of those principles, but the weight or importance of any one principle may change. There is no pre-set or universally accepted formula for developing rates.

DTE's Proposed Revenue Distribution

DTE's proposed revenue allocations are based on its CCOSS results and would move each class' rates to levels that equalize its individual class rate of return (ROR) (or 100% relative rate of return (RROR)). DTE's revenue allocations are split between those associated with the provision of power supply and distribution services. Exhibit AG-2.11 presents the Company's proposed revenue distribution under its proposed rates. The proposed revenue increase across both services and customer classes is 7.1%. On an individual customer class basis, the Company proposed increase ranges from a 2.9% increase to primary-voltage customers to a 9.1% increase to residential customers.

A RROR effectively standardizes class-specific rates of return to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific 8% ROR and further assume that the system-wide average ROR estimated by the same CCOSS is also 8%. The residential class, in this example, can be said to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (i.e., 8% divided by 8% equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall ROR (i.e., there is no cross-subsidy). A RROR that is greater than one indicates that a particular class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a RROR less than 1.0 can be said to be making a less-than-average contribution to the overall system, and is effectively being partially subsidized by other classes.

Analysis and Recommendations

The AG disagrees with DTE's proposed revenue distribution in this case. DTE's proposed revenue distribution places too great a burden on specific customer classes. For example, the Company is requesting a 7.1% overall increase in this proceeding, while also proposing that residential customers receive a 9.1% increase in total revenues, an increase that is over 1.28 times the system average increase.

The AG recommends that the Commission adopt a revenue distribution that reflects the alternative CCOSS recommendations discussed earlier in this section. The ultimate revenue distribution effects of these changes will depend on the Commission's adopted revenue requirement for the Company. Using the Company's proposed revenue requirement and Dr. Dismukes' proposed alternative CCOSS recommendations discussed earlier, the AG prepared Exhibit AG-2.11, which presents an explanatory revenue distribution along with the Company's recommended revenue distribution. Exhibit AG-2.12 then presents an explanatory comparison of the results of Dr. Dismukes' proposed alternative CCOSS recommendations at the Company's proposed revenue requirement to both current and Company proposed rates.

If the Commission does not accept the proposed changes to DTE's CCOSS methodology, the AG recommends that the Commission limit the rate increase to the residential customer class to 1.15 times the overall system average increase. In the case of the Company's proposed revenue requirement increase, which recommends a 7.1% overall system average increase, this recommendation would limit any proposed increase to the residential customer class to 8.2%. Revenue increases displaced by this proposal would be allocated on an equal proportionate basis, based on cost of service increase, to remaining classes.

This proposed alternative rate mitigation recognizes the disproportionate Company rate increases that residential customers have borne over the past decade and the detrimental impact these continual rate increases have on the affordability of electricity as laid out by Mr. Colton. The proposal also recognizes that the Company has filed five rate cases over the past five years and the proposal will effectively defer a portion of the proposed rate increase in the current proceeding to the Company's future rate filing, which will likely be filed a short duration after the close of the current proceeding. In this manner, the alternative proposal recognizes Act 341's provision allowing the Commission to implement rate increases over a period of time if the Commission determines that the proposed increase will have a material impact on customer rates.

X. CONCLUSION AND RELIEF SOUGHT

For the reasons stated above, in her expert witness' direct testimony and exhibits, and summarized in her exhibits, the Attorney General recommends that the Commission adopt her adjustments and recommendations.

Respectfully submitted,

Dana Nessel
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PROOF OF SERVICE - U-20561

The undersigned certifies that a copy of the **Attorney General's Initial Brief,** was served upon the parties listed below by e-mailing the same to them at their respective email addresses on the 14th of January 2020.

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