STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of DTE GAS COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority.

Case No. U-17999

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on October 5, 2016.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before October 24, 2016, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before November 10, 2016. The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by
action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Mark E. Cummins
Mark E. Cummins
Administrative Law Judge

October 5, 2016
Lansing, Michigan
In the matter of the application of DTE GAS COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority.

PROPOSAL FOR DECISION

I.

HISTORY OF PROCEEDINGS

On December 18, 2015, DTE Gas Company (DTE, or otherwise referred to as “the company” or “the utility,” and formerly known as Michigan Consolidated Gas Company) filed an application, with supporting testimony and exhibits, seeking authority to increase its rates, amend its rate schedules, obtain approval of certain accounting matters, and modify certain terms and conditions concerning its provision of natural gas service. DTE indicated in its application that, based on a projected test year running from November 1, 2016 through October 31, 2017, it expected to experience a revenue deficiency of approximately $182.9 million, and was thus seeking an annual rate increase in that amount. According to the company, the need for that rate increase was largely due to: (1) increased investment in the utility’s infrastructure, including increased costs associated with
maintaining the integrity of its pipeline system; (2) a decline in gas sales due to increases in its customers’ gas conservation activities; (3) decreasing gas consumption as a result of increasingly higher heating values for the gas it has sold, and will continue to sell, to its customers; (4) lower projected midstream revenues—essentially, money earned from storing and transporting gas for customers that actually consume that gas outside of DTE’s service territory—due to a reduction in its gas transportation values and gas exchange volumes; and (5) an increase in its overall operating costs. In addition, DTE contends that its proposed rate increase is supported by its need to raise the company’s rate of return on common equity to 10.75%, as well as the continuation of the revenue decoupling mechanism (RDM) allowed as a result of the settlement approved by the Commission in Case No. U-16999.

Pursuant to due notice, a prehearing conference was held in this proceeding on January 19, 2016, before Administrative Law Judge Mark E. Cummins (ALJ). In addition to DTE and the Commission Staff (Staff), several potential intervenors also filed appearances and participated at the prehearing. Intervention was granted on that date to the following parties: the Department of Attorney General (Attorney General); the Association of Businesses Advocating Tariff Equity (ABATE); ANR Pipeline Company (ANR); and Detroit Thermal, LLC (Detroit Thermal). In the course of that prehearing, a consensus schedule was established for use in this case.
This rate increase, if granted, would represent DTE’s fourth increase in its gas rates since Act 286 of 2008, MCL 460.6a, et seq., (Act 286) took effect on October 6, 2008.¹ As noted by the Commission on page 3 of its May 26, 2009 order in Case Nos. U-15768 and U-15751, “Act 286 established extremely short timeframes for concluding rate cases” such as this. For example, Section 6a(1) of Act 286 provides that if the Commission has not issued an order within 180 days of the filing of a complete application for a rate change, the utility may self-implement any portion of its proposed change through “equal percentage increases or decreases applied to all base rates” (although, if the utility’s proposal is based upon a projected test year, self-implementation shall not occur prior to the start of the projected 12-month period). See, MCL 460.6a(1). Moreover, Section 6a(3) of Act 286 requires the Commission to issue its final order within 12 months following receipt of a complete rate case filing, lest the application be considered approved. See, MCL 460.6a(3). Much to their credit, each of the parties to the present case who participated at the January 19, 2016 prehearing conference developed a consensus schedule that would allow the Commission to meet the various deadlines imposed by Act 286.

On May 11, 2016, DTE filed testimony indicating that it intended to self-implement a rate increase of approximately $103 million, effective November 1, 2016, and to be imposed by way of an equal percentage increase to

¹ By way of the Commission’s June 3, 2010 order in Case No. U-15885, and its December 20, 2012 and June 9, 2016 orders in Case No. U-16999, DTE was effectively granted authority to increase its general gas rates by a total of $147,862,000 annually.
each of its various rate classes. See, Exhibit A-20. In this regard, MCL 460.6a(1) provides that:

If the commission has not issued an order within 180 days of the filing of a complete application, the utility may implement up to the amount of the proposed annual rate request through equal percentage increases or decreases applied to all base rates.... [However], if the utility uses projected costs and revenues for a future period in developing its requested rates and charges, the utility may not implement the equal percentage increases or decreases prior to the calendar date corresponding to the start of the projected 12-month period. For good cause, the commission may issue a temporary order preventing or delaying a utility from implementing its proposed rates or charges.

In the present case, the 180-day period within which the Commission had the opportunity to issue an order regarding self-implementation ended on June 18, 2016, which (quite obviously) was well before the commencement of the 12-month test year period beginning November 1, 2016. Based on the above-quoted statutory language, the Commission found (correctly, at least in the eyes of this ALJ) that DTE should not be allowed to self-implement any portion of its proposed rate increase prior to November 1, 2016. See, the Commission’s June 9, 2016 order in Case No. U-17999 (the June 9 order), at p. 2. However, the Commission did reserve the authority to “issue further orders under MCL 460.6a(1) regarding self-implementation of new rates, if necessary.” See, Id.

Evidentiary hearings were conducted with regard to the case in chief on June 21 and 24, 2016. DTE offered testimony and exhibits from a total of 17 witnesses, and the Staff did the same with regard to 11 witnesses. Also, ABATE and the Attorney General each provided testimony and exhibits from one witness.
Overall, the record consists of 3 volumes of transcript totaling 1,286 pages, as well as 137 exhibits.

Largely consistent with the agreed upon schedule for this case, initial briefs were filed on July 27, 2016, by DTE, the Staff, ABATE and the Attorney General. Likewise, reply briefs were filed on August 16, 2016, by all of the parties except ANR and Detroit Thermal.

The filings received in this matter proposed a wide range of suggested revenue deficiency figures, some of which have changed over the course of the case. For example, DTE initially asserted (through its application and pre-filed testimony) that its projected revenue deficiency was approximately $182.9 million. However, after agreeing to several changes proposed by other parties to this proceeding, it ultimately concluded that its overall revenue deficiency for the projected test year was actually only $178,245,000. See, i.e., DTE’s initial brief, pp. 8-10, as well as the utility’s reply brief, p. 90. In making its assertions with regard to the alleged revenue deficiency, the company went on to note that, because its existing $40.8 million annual Infrastructure Recovery Mechanism (IRM) surcharge [which is used to pay for capital investments relating to DTE’s meter move out, cast iron pipe replacement, and pipeline integrity improvement projects] would be replaced by a significantly smaller surcharge, the effective rate increase incurred by its customers would be more in the range of $150.7 million per year. See, DTE’s initial brief, p. 6. In contrast, the Attorney General claims that any rate relief sought

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2 Although the Attorney General’s initial brief indicates that it was authored and sent on July 27, 2016, it does not appear to have arrived until the following day. Again, to their credit, none of the other parties to this case chose to claim that the Attorney General’s brief should not be considered in this proceeding.
in this case should not exceed $79.3 million, whereas the Staff contends that the appropriate figure should be approximately $120.8 million. See, Attorney General’s initial brief, p. 2; See also, Staff’s initial brief, p. 3.

As in most cases of this nature, a large amount of testimony and argument has been presented with regard to issues that are both numerous and complex. In addition to the typical issues arising in general rate cases like this, a significant portion of the record dealt with (1) the utility’s cost of service and the allocation of that cost to various customer classes, (2) the proposed level of spending on IRM, (3) the effect of the company’s RDM, (4) the impact of increasingly higher heat contents found in the gas DTE has supplied, and plans to continue to supply, to its customers, and (5) various rate design issues raised by both the utility and its ratepayers. Despite the number and complexity of these various concerns, Act 286 requires (as noted earlier) the issuance of a Commission decision within 12 months after the application’s filing. Thus, in the interest of issuing this Proposal for Decision (PFD) in a timely manner, not all of the material presented in this case will be expressly discussed. The various parties’ summaries of the evidence and arguments in support of their respective positions are fully set forth in their pleadings, briefs, and reply briefs, and the underlying basis for the same can be found in the evidentiary record. Thus, although the ALJ has considered the entire record in arriving at the findings and conclusions expressed below, only those arguments, testimony, and exhibits that are necessary for a reasoned analysis of the disputed issues will be specifically addressed in the PFD.
II.

TEST YEAR

In every general rate case, the initial task is the selection of an appropriate test year. Essentially, this task is comprised of two components.

First, a decision must be made regarding the 12-month period to use in setting the utility’s new rates. In this proceeding, DTE proposed using the 12-month period ending October 31, 2017 for that purpose. See, DTE’s initial brief, p. 15. As none of the other parties objected to the use of this proposed time-frame, the ALJ recommends adopting that 12-month period for use in this case.

Second, a determination must be made regarding how to best establish values for the various levels of revenue, expenses, rate base, and capital structure used in the rate-setting formula. Generally, these values may consist of historical, future, or a combination of historical and future data. A historical test year uses actual operating data that, once audited, is generally adjusted for known and measurable changes. A future test year (frequently referred to as a projected test year) uses projections to determine the levels of revenue, expenses, rate base, and capital structure for a future period of time.

Although parties often clash over what type of test year is most appropriate in a given case, until fairly recently the Commission had consistently expressed a preference for using historical, as opposed to purely projected, data. See, i.e., the Commission’s November 7, 2002 order in Case No. U-13000, at p. 13. Nevertheless, Section 6a(1) of Act 286 states that a utility may “use projected costs and revenues for a future consecutive 12-month period” to develop its requested

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gas or electric rates and charges. MCL 460a(1). This statutory provision has altered the debate significantly by specifically indicating that Michigan’s regulated gas and electric utilities have the right to base their general rate case filings exclusively upon projections of anticipated activities and their related expenses, should they so desire. Nevertheless, what it does not do, however, is demand that either the parties or the Commission blindly accept any and all numbers springing from a utility’s projections of future actions and the potential costs arising from those actions.

The Commission acknowledged this fact in its January 11, 2010 order in consolidated Cases Nos. U-15768 and U-15751 (January 11 order), where it stated that:

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 of 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 projections 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.

January 11 order, p. 9.

Apparently both anticipating (in its pre-filed testimony) and recognizing (as expressed in its post-hearing briefs) the Commission’s view concerning what currently constitutes the preferred approach, DTE began with historical data from the 2014 calendar year, and then “normalized and adjusted those results for inflation and other known and measurable changes.” DTE’s initial brief, p. 15.
Again, none of the parties specifically objected to using that approach. As a result, the test year information provided by the utility will be used as the starting point for discussions concerning the various issues raised in the course of this case.3

III.

RATE BASE

In general terms, the rate base for a gas utility like DTE consists of total utility plant (i.e., the capital invested in all plant in service, plant held for future use, and construction work in progress [CWIP], if any), less the company’s depreciation reserve (consisting of its accumulated depreciation, amortization, and depletion), plus the utility’s working capital requirements.

In this case, DTE initially proposed setting its total company rate base for the test year at approximately $3.720 billion, which consisted of about $2.720 billion in net utility plant and $1 billion in working capital. See, i.e., DTE’s initial brief, p. 16; citing 2 Tr. 337 and Exhibit A-9, Schedule B1. However, in its initial brief, the company proposed reducing its total rate base to $3.716 billion arising from (1) capital adjustments relating to a change in “demolition fees from non-municipal cut and cap” operations, (2) an adjustment to accumulated depreciation to reflect “a correction to depreciation expense,” and (3) a “reduction in working capital to reflect

3 Nevertheless, the ALJ believes he would be remiss in failing to note--once again--that, after the more heavily-accepted use of projected test years has taken place (generally occurring since the enactment of Act 286, roughly eight years ago), both the frequency and size of general gas and electric rate increases has risen significantly. Although other factors have likely been involved during this period, a general reconsideration--by all interested parties--regarding both the efficacy and the reasonableness of making such significant use of projected test year figures may be warranted in the future.
the updated estimate of the Regulatory Asset Demolition Fees.” See, Id.; See also 3 Tr. 1120, wherein DTE cites to Staff Exhibit S-12.1. Also, in its reply brief, the utility adopted the Staff’s suggested working capital figure of approximately $1.220 billion, thus pushing the company’s final rate base request to a total of $3,739,371,000. See, DTE’s reply brief, p. 6, citing Attachment A, page 2, line 22.

For its part, the Staff projected DTE’s rate base for the plan year as being about $3.724 billion, which is approximately $14.9 million lower than the utility’s above-stated figure. See, Staff’s initial brief, p. 3. In contrast, the Attorney General seeks to reduce the company’s proposed rate base by $250.2 million for its proposed test year, which would resulting in a net figure of approximately $3.489 billion. See, Attorney General’s initial brief, p. 44.

Through both testimony and briefs, the parties have raised several concerns regarding various areas of the company’s rate base proposal. Although many issues have either been resolved or essentially waived4 by the parties, each of the currently-existing disputes argued by the participants to this case is addressed within the following discussion of net utility plant and working capital.

4 In some instances, although a reduction in the utility’s suggested rate base--and, similarly, the company’s recommended operating and maintenance (O&M) expense levels--was proposed by a witness, or a request was made in testimony to such things as the monthly residential customer charge or the monthly general service charge, the party did not provide any specific citations to supporting testimony, and also failed to provide any explanation or analysis in support of its witness’ proposed reduction. Doing so thus leaves the ALJ, and ultimately, the Commission, with the task of supporting the witnesses’ initial position. However, Michigan Courts have long held that failure to brief an argument is tantamount to abandoning it. See, i.e., Wilson v Taylor, 457 Mich 232, 243 (1998). Based on that decision, and in light of the extremely tight schedule necessitated by Act 286, this PFD will not address those essentially abandoned matters.
A. Net Utility Plant

Various issues continue to exist regarding the level of net utility plant that should be adopted for use in this rate case proceeding. These relate to (1) disallowances suggested by the Staff and the Attorney General to remove projected contingency expenditures on a number of capital improvement projects proposed by DTE, (2) the investment of capital in the utility’s revenue protection program, (3) the Staff’s recommendation that all costs related to the purchase and injection of incremental base gas should be shared by the company and its customers, (4) a dispute between the company, the Attorney General, and the Staff regarding the likely cost of gas to be purchased during the proposed test year, (5) the Attorney General’s claim that costs arising from DTE’s involvement with the NEXUS Pipeline project will be unjustifiably borne by the utility’s ratepayers, and (6) a dispute between the company and the Attorney General regarding $17.9 million related to the relocation of gas facilities and related work arising from the proposed construction of the Gordie Howe International Bridge (GHIB), which will further link the metropolitan Detroit, Michigan and Windsor, Ontario areas.

1. Expected/Proposed Capital Contingency Expenditures

According to DTE, the utility “has made or will make $931.2 million of capital expenditures from the end of the historical test year to the end of the projected test year,” which covers the period from December 31, 2014 through October 31, 2017.\(^5\) In support of those expenditures, the company contends that they should be

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\(^5\) According to DTE, it also plans to collect the revenue requirement associated with $127.6 million of capital expenditures annually beginning January 1, 2017 through a new five year Infrastructure Recovery Mechanism (IRM) surcharge. See, DTE’s initial brief, p. 16.
approved in their entirety because “they are prudent investments” in DTE’s natural gas system that are necessary for the utility “to maintain its safe and reliable system for distributing natural as to customers.” DTE’s initial brief, p. 16. As asserted by the company’s witness on this matter, Alida D. Sandberg, DTE’s Director of Engineering Services, the spending in question includes routine spending (for things such as distribution plant, transmission and gas storage facilities, vehicles, building improvements, and computer equipment), as well as investment in a host of new projects (such as new market attachments, advanced metering infrastructure [commonly referred to as AMI], the NEXUS pipeline project, the Belle River Compressor project, work related to the Gordie Howe International Bridge [referred to as the GHIB], the Milford Junction Loop, and the Revenue Protection Program [RPP]). See, 2 Tr. 680-704.

Included in that proposed level of spending is $11,957,000 in contingency costs related to its new projects, the request for these funds essentially being based on the utility’s belief that the total expense of those projects may not have been fully foreseen. The Staff and the Attorney General contend that approval of such contingency costs would be patently unreasonable and inappropriate. See, Staff’s initial brief, pp. 4-7; See also, Attorney General’s initial brief, pp. 47-48. According to the Staff’s witness on this issue, Catherine Cole, Executive Advisor to Commissioner John Quackenbush and an Assistant in the Commission’s Operations and Wholesale Markets Division, the Staff generally believes that:
It is inappropriate for the Company to earn return of and return on projected contingency expenditures for three reasons: (1) the contingency expenditures may not be incurred at all; (2) if some expenditures are ultimately incurred, the final amount could be anything from $1 to the amount projected (or even more), while the final amount expended is inherently unknown at the beginning of the test year, as is the case with any cost category, the fact that a projection of contingency expenditures is really a range of possible spending, and not a target, creates a much higher degree of uncertainty regarding future expenditures than is found with projected expenditures in other cost categories; [and] (3) allowing contingency expenditures into rate base may dampen incentives for cost control.

3 Tr. 1130. According to the Staff, adopting the total capital expenditure disallowance proposed by Ms. Cole would necessitate reducing DTE’s proposed rate base figure by $9,380,000. See, Staff’s reply brief, p. 1. Based both on the Staff’s analysis and testimony offered by its own witness, Sebastian Coppola, an Energy Consultant and President of Corporate Analytics, Inc., the Attorney General essentially agrees with the Staff on the need to exclude DTE’s proposed capital contingency expenditures from the rate base figure ultimately adopted in this case. See, Attorney General’s initial brief at pp. 46-47.

The ALJ finds the assertions of the Staff and the Attorney General on this issue to be persuasive. This finding is based on the following three factors.

First, with regard to DTE’s apparent belief that the inclusion of some level of contingency expenditures in a project’s total projected cost is a standard project management practice, that is not actually the salient point. Rate recovery and project management are not the same thing. Moreover, in the course of In re Application of Indiana Michigan Power Company for a Certificate of Necessity, 307 Mich App 272 (2014), that utility unsuccessfully offered similar arguments to the Court of Appeals that have now been raised by DTE (i.e., claiming that a projected
contingency expenditure is an appropriate and necessary component of the cost estimate for any major capital project, and relying on what is claimed to be the asserted standard practice in the utility industry).  See, 307 Mich App 272, 291-293.

Second, although DTE essentially contends that it is not an accepted industry practice to deny a request for contingency funding as an incentive for cost control, it is not clear what industry practice the utility is referring to.  Although it makes sense to consider contingency funding as a part of project cost estimates in most circumstances, the company’s blanket statement about general industry practice would seem to ignore the unique characteristics of the regulated gas industry.  Approving the inclusion of contingency amounts in capital expenditures projected by utilities to be rate-based in a future period—which guarantees recovery of those amounts plus a rate of return—is materially different from general practice in a variety of industries, and thus requires very careful scrutiny.  It is this concern (i.e., that once the utility is allowed to earn a return on any of its proposed contingency expenditures, that return will remain with the utility regardless of whether the contingency ever actually occurs and is thus paid for by the company) which makes a regulated utility like DTE different from other business entities.

Third, the Commission’s November 19, 2015 order in Case No. U-17735 (the November 19 order) specifically addressed the issue of whether projected contingency expenditures should be included in rate base, and came to the conclusion that they should not.  See, the November 19 order, p. 11.
For all of these reasons, the ALJ recommends that the Commission disallow the contingency costs requested by the utility in this case, thus resulting in a total reduction to DTE’s projected test year rate base of $9,380,000.6

2. Capital Expenditures for DTE’s Revenue Protection Program

Ms. Sandberg also testified regarding DTE’s request for the inclusion of its proposed spending on cutting and capping service lines due to theft and/or non-payment, as well as the expected cost of reconnects and service renewals following disconnection. See, 2 Tr. 703-704. According to her, from the end of the historical test year (on December 31, 2014) through the end of the projected test year (on October 31, 2017), “DTE has made or will make $14.7 million of revenue protection expenditures” arising from these activities. 2 Tr. 704. As such, the utility added those costs, in part, to its rate base request. Specifically, it requested cost recognition of $4,546,883 for 2016 and $6,951,573 for 2017, resulting in a total rate base increase of $11,498,456. See, DTE’s reply brief, p. 10.

The Staff, through testimony offered by Cynthia Creisher, a Public Utilities Engineer in the Commission’s Operations and Wholesale Markets Division, asserted that DTE unjustifiably used a mere three-year average to estimate the cost of its service line abandonments and renewals expected during the 2016 through

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6 According to the Staff’s reply brief, the “corresponding corrections to plant, accumulated depreciation, and depreciation expense” lead to a net increase of approximately $25,000 to the revenue requirement from the level stated by the Staff in its initial brief. Staff’s reply brief, p. 1.

Also, noting that Ms. Sandberg indicated that capital expenditures for routine storage plants are based on risk-based analyses and gas market requirements, the Staff essentially asked that DTE be directed to meet annually with the Staff and provide a report “on the results of the risk-based assessments and continuous performance monitoring and testing conducted,” as well as providing regular updates regarding “capital projects undertaken of planned to ensure the integrity and deliverability of DTE’s storage system.” Staff’s initial brief, p. 8. The utility did not express disagreement with the Staff’s request, and--finding it both reasonable and likely to be beneficial to all of DTE’s customers--the ALJ recommends that the Commission adopt this request.
2017 test year period. Specifically, and as stated in Exhibit S-7.5, Ms. Creisher pointed out that the utility’s figures were based solely on “work completed from 2012 through 2014,” thus ignoring “the reduction of abandonments and renewals completed in 2015 compared to work completed in previous years,” as well as the “overall variance in the work completed year over year, particularly for service abandonments.” 3 Tr. 1351. According to her, a more accurate methodology would be to use a five-year average to estimate these activities and their related expenses, which would--by the way--include the noticeably lower figures from 2015. See, Id. In light of Ms. Creisher’s analysis, the Staff recommended that projected increases to DTE’s test year rate base for its revenue protection program should be only $4,145,585 for 2016 and $5,482,806 for 2017, which results in a test year figure that is $9,628,391. See, 2 Tr. 1152. As a result, the Staff’s total figure for the 2016-2017 period was approximately $1.9 million lower than that used by the company in estimating its test year rate base.

According to DTE, part of the $1.9 million difference between the figures proposed by the utility and the Staff is due to:

[The] Staff’s use of an erroneous cost per unit for 2017 service line abandonments ($648 instead of DTE’s $595) and renewals/reconnects ($1,497 instead of DTE’s $1,861). DTE submitted a supplemental response with corrected data to an audit request, “which Staff did not agree with and therefore did not take into consideration in its analysis” (Staff Initial Brief, p. 10). However, Staff provides no support for their disagreement with this amount in their testimony or in their initial brief. Specifically, Staff’s initial brief does not explain why Staff did not use the corrected amount, but instead makes the conclusory assertion that DTE did not provide an adequate explanation for the increase in the cost per unit (Staff Brief page 10). Both amounts, the corrected and the uncorrected, were provided by DTE and supported similarly (2 T 737-738). Thus, Staff’s argument is specious and not based on the facts of this case. Therefore,
correcting the cost per unit of 2017 service line abandonments would reduce Staff’s proposed reduction in expenditures by $674,000.

DTE’s reply brief, pp. 10-11 [citation omitted]. The remainder of Staff’s proposed reduction is, according to the utility, simply due to the above-mentioned differing projections of units affected based on the Staff’s use of a five-year expenditure average versus the three-year spending average used by the company. See, Id., p. 11.

Based on the testimony and briefs submitted in this case, the ALJ is not certain exactly why the Staff found that the supplemental discovery response (and the revised per-unit costs for service disconnections expected to be undertaken during 2017 therein provided by DTE) should be summarily ignored. Lacking anything else to use in this regard, the ALJ finds that the higher figures provided by the utility should be adopted for use in this case.

On the other hand, the ALJ agrees that the five-year expenditure average used by the Staff in computing DTE’s likely level of spending on revenue protection programs during the test year is preferable to the three-year average proposed by the company. As in most instances, and barring some well-defined cause for making one of the years’ results a clear outlier, the longer of two periods being espoused by various parties to a rate case inherently has more credence than the shorter period. In the present case, no well-supported reason for excluding the figures for 2015 has been provided. As such, the ALJ finds that the general numbers gleaned from the Staff’s five-year average of per-unit activity will likely produce a result that is more reflective of DTE’s actual expenditures during the test year.
For these two reasons, the ALJ recommends that the Commission grant the Staff’s request to reduce DTE’s projected rate base figure with regard to revenue protection program capital expenditures, however not by the full $1.9 million the Staff requested. Rather, the ALJ finds that the Staff’s proposed adjustment should be reduced to reflect the revised per unit cost of projected service disconnections provided by the utility in its supplemental discovery response, albeit adjusted for its actual rate base impact. Taken together, these findings support a reduction in the company’s proposed rate base of $1,490,000, as reflected on Attachment A to this PFD.

3. The Staff’s Proposed Cost Sharing Regarding Incremental Base Gas

Prior to 2008, DTE made upgrades to various gas storage fields which it felt had additional available cycling capacity, and thus needed a lesser volume of base gas (“base gas” is essentially the amount of gas needed to remain in a storage field on a permanent basis, and whose presence—and thus its associated pressure—allows the storage field to continue operating). Because of the perceived need for less base gas, the Commission approved, in Cases Nos. U-14800 and U-15042, DTE’s request to release a portion of the previously sequestered base gas for sale, essentially with the stipulation that both the company and its ratepayers would share in the benefit of the release of what was relatively low-cost gas. Unfortunately, based on operational limitations that DTE subsequently experienced in the recent past (namely, historically cold weather during the 2013-2014 winter heating season, which led to potential gas cycling problems), DTE determined that it was necessary to make changes to a pair of its gas storage fields, basically in the
form of additional compression, as well as reconverting 1.9 billion cubic feet (Bcf) of working gas ("working gas" is essentially the gas that the utility sends through its pipeline system for consumption by its customers) into base gas at its Belle River Mills storage facility. See, 3 Tr. 1219-1220, citing Exhibit S-11.5.

Ronald Ancona, Manager of the Act 304 and Sales Forecasting Section within the Commission’s Regulated Energy Division, suggested that, although the company proposes to have its ratepayers cover the full cost of reconverting the above-mentioned 1.9 Bcf of working gas to base gas, “the cost of reconversion be shared between DTE and [its] customers, just as the benefits were shared.” 3 Tr. 1220. “In other words,” he continued, under his proposal, “customers should only be responsible for 50% of the costs related to the reconversion of working gas to base gas.” Id.

In contrast, DTE contends that no portion of this addition to rate base should be borne by the utility (but rather all of those costs should be assigned to its customers), on the basis that “customers have already benefited significantly from the base gas sale through a lower cost of gas supply,” as well as the utility’s “deferral of a general rate case filing,” and (at least until now) its corresponding rate increase. DTE’s reply brief, p.14. Moreover, the utility contends:

Staff’s proposal would provide customers with inappropriate additional benefits, and levy a corresponding significant and unwarranted detriment on the Company. Moreover, a portion of the proceeds from the base gas sale was used to provide funding for residential energy efficiency programs to benefit low income and other residential customers. Therefore, all base gas costs are prudent expenditures that should be included in rate base.
DTE’s reply brief, p. 14, citing 2 Tr. 108-109. As such, DTE argues that the Staff’s suggested reduction in the utility’s overall projected test year rate base, valued at $4.1 million,⁷ should be rejected. See, Id.

The ALJ is unpersuaded by the utility’s assertion that the cost of reinserting the needed 1.9 billion of base gas into its storage system should not be shared--on a 50/50 basis--between the company and its customers. Because both benefited from the initial removal of this low-cost gas, the ALJ finds that both should be held equally responsible for its restoration. It is therefore recommended that the Commission reduce DTE’s projected test year rate base figure by $4,072,000, which is necessary to ensure that the utility bears its portion of the cost of reconverting that 1.9 billion of working gas to base gas, and is thus reflected on Attachment A to this PFD.

4. Concerns Regarding the Utility’s Cost of Gas

In his revised direct testimony, George Chapel, DTE’s Manager of Market Forecasting, projected that the jurisdictional cost of natural gas procured by the utility would be $3.920 per thousand cubic feet (Mcf) during the period of November 2016 through March 2017, and would then drop to $3.605 per Mcf for the April 2017 to October 2017 period. See, 2 Tr. 567. These figures were based

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⁷ The $4.1 million figure, which was detailed by Staff witness Nyrhe Royal [a Senior Public Utilities Engineer for the Commission’s Regulated Energy Division] in 3 Tr. 1234-1235, and also set forth on Exhibit S-2, Schedule B-1, Column D, assumes that the Staff’s cost of gas (as opposed to that proposed by the utility) is adopted in this case. Because this PFD indeed recommends adopting the Staff’s suggested cost of gas, the $4.1 million figure suggested by the Staff and acknowledged by DTE, is recommended as the necessary reduction to the utility’s proposed test year rate base figure in this case.
on the company’s proposed system average heating value of 1.087 million British thermal units (MMBtu) per cubic feet of gas.

Both the Attorney General and the Staff disagree with Mr. Chapel’s assessment regarding the cost of gas for the projected test year. According to the Attorney General’s witness, Mr. Coppola:

To calculate its projected average Btu factor of 1.087, the Company applied a one-year trend analysis to the historical 12-month Btu values from October 2014 to September 2015 and then averaged the resulting values for the period November 2016 to October 2017. The flaw in the Company’s forecast is the assumption that the Btu value of the gas purchased and delivered to customers will continue to escalate unabated over the coming months in 2016 and 2017. Over this two-year time period, the Company is forecasting that the Btu value will range from 1.057 in January 2016 to 1.097 in October 2017. At no time prior to January 2016 has the company experienced a Btu value reaching or surpassing the low end of the forecasted range of 1.057. In fact, in response to a data request, the Company stated that Btu values for January through March 2016 have been in the range of 1.044 to 1.047.

From the BTU data provided by the Company, it appears that the heat content of natural gas purchases took a marked change in August 2014 when it increased from below 1.020 to 1.025. During 2015, Btu values increased steadily to an average of 1.042. However, during the first three months of 2016 the Btu values have been in the same vicinity of 1.042. Therefore, it appears that the Btu content of gas purchases has stabilized. This would make sense given that natural gas prices have declined since the Company’s forecast in October 2015 providing less incentive for producers to leave ethane in the gas stream. Realistically, there is also a limit to how much more ethane producers can leave in the natural gas stream. Mathematically, the Company’s forecast with its regression trend assumes no limit.

3 Tr. 995-996. As such, the Attorney General contends that, because “the most recent actual BTU values” reflect a more stable Btu level than assumed by DTE, the Btu forecast—and its related price and sales level adjustments proposed by the utility—are “just not realistic.” Attorney General’s reply brief, p. 12.
For its part, the Staff—as did the Attorney General—proposed using a single price point for the cost of natural gas for the November 2016 through October 2017 test year period, albeit its price was closer to the utility’s figure than was the Attorney General’s. As testified to by Ms. Royal, the Staff’s approach was based on four monthly variables: (1) the volume of the utility’s long term or other spot market purchases, (2) the cost of those purchases, (3) the volume of the projected city gate and market-based purchases, and (4) gas transportation costs. See, Staff’s initial brief, p. 24. Based on Ms. Royal’s analysis, the Staff contends that the average monthly cost of gas to be used in this case should be $3.6089 per Mcf, which “is the sum of the monthly costs of the total system supply purchases divided by the monthly volumes of the system supply purchases,” and was the price the Staff applied to the reconverted base gas injected into the Belle River Mills storage field. 3 Tr. 1234-1235, Exhibit S-10.3, Revised, p. 2, and Exhibit S-2, Schedule B-1, Column D, line 8. The above-stated figures, the Staff goes on to assert, are based upon its proposed system average heating value of 1045 Btu per Mcf. Staff’s initial brief, p. 24.

The ALJ agrees with the Attorney General and the Staff regarding the overall theory that DTE’s proposed two-part jurisdictional cost of gas proposal should be rejected. Moreover, of the three proposals, the ALJ finds that the Staff’s $3.6089 per Mcf figure (which is based on a heating value of 1045 Btu/Mcf), appears to be less speculative, more closely aligned with recent cost data, and better supported by the evidence presented in this case than the cost of gas figures offered by the other parties. As a result, the Staff’s figure has been used in the preceding section.
concerning the cost sharing of the reconversion of working gas to base gas, and will likewise be used in the calculation of the utility’s projected net operating income later in this PFD.

5. **NEXUS-Related Capital Expenditures**

According to DTE, it projects $201 million of capital expenditures to be made from 2015 through October 31, 2017 to upgrade its pipeline system in order to be better facilitate the expected connection to the NEXUS pipeline project, and the subsequent transportation of gas moved through that pipeline. See, DTE’s initial brief, p. 18, citing 2 Tr. 695-696. According to Ms. Sandberg, that spending would cover “major upgrades” at the utility's Willow Gate Station, Willow Run Compressor Station, and Milford Compressor Station. 2 Tr. 695.

The utility asserts that “customer rates will not be impacted in this proceeding” by the above-mentioned upgrades due to their assignment to the company’s Allowance for Funds Used During Construction (AFUDC). DTE’s reply brief, p. 12. Moreover, the company contends that when the pipeline’s related facilities are actually placed into service (which would be, it appears, shortly after the end of the projected test year used in this case), “the revenue associated with the NEXUS project will support the invested capital including accumulated AFUDC.” Id, citing 2 Tr. 697. Thus, the utility claims that the “revenue requirement associated with the NEXUS project will never be borne by [DTE’s] retail customers.” Id.
The Attorney General opposes any form of Commission approval regarding costs arising from the NEXUS-related construction projects. First of all, he points out that although the interstate transportation pipeline itself is still awaiting approval by the Federal Energy Regulatory Commission (FERC), which may or may not be granted, DTE “is proceeding with the planned facilities upgrades and modifications.” Attorney General’s reply brief, p. 24. Second, he asserts that in response to a discovery request, the utility provided a letter of agreement with one of its affiliated companies, namely DTE Pipeline Company, whereby DTE was promised to be “reimbursed for certain costs incurred in building certain facilities if the NEXUS project is abandoned.” Id. However, the Attorney General continues, all follow-up discovery questions seeking clarification of the agreement’s terms have gone unanswered.8 Furthermore, he contends that the utility “has entered into a lease agreement with NEXUS Gas Transmission Company” by which that entity will lease transportation capacity from DTE to move gas through DTE’s transmission facilities on behalf of NEXUS’s other customers. Id., p. 25. According to the Attorney General, repeated efforts to obtain that particular lease agreement have gone unheeded. See, Id. He thus supports rejecting DTE’s requests regarding the NEXUS-related capital expenditures or, at a minimum, having the Commission direct the utility to “include a cost/benefit analysis in [any] future rate case” in which the company seeks to recover costs related to the NEXUS project. Id., p. 26.

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8 Exhibit AG-21 includes a copy of the letter of agreement, as well as the unanswered questions posed by the Attorney General.
Albeit with significant trepidation, the ALJ finds that the totality of the record supports taking DTE at its word that ratepayers will be held harmless from the utility’s interactions (both with regard to facilities upgrades proposed in this case and the revenue expected to ultimately be received as a result of them) concerning the NEXUS pipeline project. Nevertheless, it is recommended that the Commission only grant the approvals sought by DTE in this regard on a contingent basis and, as proposed by the Attorney General, require the submission of a full cost-benefit analysis prior to allowing any form of cost recovery regarding capital expenditures made that relate to the NEXUS project. Specifically, the ALJ believes that failure by the utility to both provide a cost-benefit analysis and adequate testimony supporting it should preclude any cost recovery whatsoever for those expenditures.

6. GHIB-Related Capital Expenditures

The Attorney General points out that, in Exhibit A-9, Schedule B6.1, DTE has projected capital expenditures (for 2015, 2016, and the first 10 months of 2017) in the total amount of $17.9 million for the relocation of facilities--and related work--in conjunction with the construction of the GHIB. This would, it appears, translate into a test year rate base increase of $11,871,000, if approved by the Commission in this case. See, Attachment A to this PFD. According to him, and in response to a discovery request regarding this issue, the utility asserted that it believes that the Windsor-Detroit Bridge Authority (WDBA) would likely pay for a majority of the cost of relocating DTE’s facilities to accommodate construction of the bridge. See, Attorney General’s initial brief, p. 51. “Nevertheless,” the Attorney General continues, “the Company has included these capital expenditures in the forecasted
rate base.”  Id.  Moreover, he continues, it is unclear who (be it the State of Michigan or some other entity) will ultimately own the facilities on the United States’ side of the bridge.  In light of this uncertainty, and to “provide the Company with every incentive to recover the cost of relocating its facilities from the parties responsible for building and owning the bridge,” he contends that the capital expenditures related to the GHIB should “not be included in the rate base in this rate case at this time.”  Attorney General’s initial brief, pp. 51-52.

In apparent response, DTE asserts that notwithstanding the Attorney General’s suggestion that--as with the potential GHIB-related expenses--capital improvement projects which do not generate new revenue place an unbearable burden on the utility’s customers, much of the company’s capital expenditures are “undertaken to meet government mandates, such as the required relocation of gas facilities due to municipal infrastructure improvements.”  DTE’s initial brief, pp. 9-10.  While those expenditures of the utility’s capital may not generate additional revenue, the company concludes by asserting that they are generally needed to “ensure the safe and reliable operation of [DTE’s] system.”  Id., p. 10.

Notwithstanding DTE’s arguments, the ALJ finds that the more cautious route proposed by the Attorney General regarding the inclusion of proposed capital costs relating to the GHIB’s construction in the utility's rate base at this time are preferable.  This conclusion is based on two points.  First, the Detroit International Bridge Company, owner of the Ambassador Bridge currently linking Detroit and Windsor, has been--and continues to be--in a long and well-known struggle to avoid the construction of any additional border crossings in southeast Michigan/
southwestern Ontario. Lawsuits in this regard are continuing at this date. Second, and as noted by the Attorney General, it does appear that at least some uncertainty exists regarding whether, when, and to what degree the capital expenditures made by DTE to reconfigure its pipeline system in the GHIB area will be returned to the utility--and, hopefully, its ratepayers--by the WDBA or any other entity (assuming, of course, that the bridge is actually constructed). Based on these factors, the ALJ recommends that the Commission refrain from including in its current rate base for this utility any of DTE’s proposed capital expenditures relating to the GHIB. As a result, in this case, it appears that DTE’s proposed rate base figure should be reduced by $11,871,000 as a result of this particular finding.

7. **CWIP**

The next issue normally addressed regarding what specific level of test year net utility plant should be adopted for use in a case like this is the matter of CWIP (which is essentially an addition to a utility’s rate base designed to recognize capital investment in a project--or projects--that have not yet been completed). However, in this proceeding, none of the other parties appear to have challenged (at least in their briefs or reply briefs) DTE’s proposed level of CWIP. As a result, the ALJ suggests adopting the utility’s proposed figure when calculating the company’s net total rate base for the test year in question.

8. **Accumulated Provision for Depreciation**

The depreciation reserve balance (otherwise referred to as the accumulated provision for depreciation) covering a particular test year is developed by applying the utility’s then-effective depreciation rates to its average plant-in-service for the
test year in question. Based on testimony and exhibits provided by Robert Nichols, Manager of the Revenue Requirements Section of the Commission’s Financial Analysis and Audit Division, the Staff’s projected DTE’s accumulated provision for depreciation as being $2,166,429,000, which represents an increase of $1,573,000 from the figure set forth in the utility’s initial rate case filing (assuming adoption of the Staff’s position on several capital expenditure adjustments, like those addressed above). See, 3 Tr. 1118. In addition, the Staff recommended increasing the company’s overall accumulated depreciation level—and thus reducing net utility plant in service—by an additional $1,717,000, which Mr. Nichols found necessary to correct a $3,433,000 error in DTE’s computation of its test year depreciation expense. See, Id.

Because the ALJ has recommended adoption of nearly all of the Staff’s suggested adjustments to the rate base figures proposed by DTE, supra, the first increase in the utility’s accumulated provision for depreciation offered by way of the testimony from Mr. Nichols should be adopted (albeit, with the recognition that the figures cited in both his testimony and the Staff’s briefs will need to be adjusted slightly to reflect the fact that the PF D recommends a reduction in projected rate base of $1,490,000 with regard to the revenue protection/cut and cap program, as opposed to the full $1.9 million initially requested by the Staff). As for the second adjustment suggested by the Staff, the company expressed agreement with that $1.7 million change, which it concurs is needed to reflect “the impact of corrected
depreciation rates on accumulated depreciation” for the computation of net utility plant.\textsuperscript{9} See, DTE’s initial brief, p. 9, and its reply brief, Attachment A, p 2.

**B. Working Capital**

Working capital is the amount of funds required to bridge the gap between the time of payment of a utility’s expenses and the receipt of revenues from its customers. In the present case, at least initially, DTE and the Staff proposed somewhat different figures for the utility’s working capital allowance. Specifically, and as reflected on Appendix B of the Staff’s initial brief, DTE suggested using $999,731,000 as the working capital figure, whereas the Staff recommended using a figure of $1,021,860,000. Based on testimony provided by the Staff’s witness on this issue, Mr. Nichols, the $21,949,000 difference between these parties’ figures is based on: (1) the Staff’s upward adjustment of $31,386,000 to “gas in underground storage – current,” (2) a $9,764,000 increase to the utility’s Gas Customer Choice (GCC) program’s deferred asset account, (3) a reduction of $18,214,000 to “intercompany notes receivable,” and (4) a downward adjustment of $987,000 to “regulatory assets – demolition fees.” Staff’s initial brief, pp. 24-25, citing 3 Tr. 1119.

Following its review of Mr. Nichols’ testimony and the Staff’s resulting proposal with regard to working capital, DTE decided to adopt the Staff’s total figure of approximately $1.022 billion. See, DTE’s reply brief, p. 15. In contrast, the utility notes, the Attorney General asserted in its initial brief that the Commission should adopt a $61.3 million reduction to working capital. See, Id. “However,” the

\textsuperscript{9} Nevertheless, it appears that to completely fair to the utility, $285,000 should be added back as a capital expenditure adjust for the effect on accumulated depreciation.
company asserts, “the [Attorney General] does not specifically address the components of his proposed $61.3 million reduction to working capital in his Initial Brief.” Again, DTE points out that, as stated by the courts in the *Wilson v. Taylor* case specifically cited in footnote 4 of this PFD, it is insufficient for a party to simply announce a position or assert an error, and then simply leave it up to the ALJ of the Commission to “discover and rationalize the basis for [his] claims, or unravel and elaborate for him his arguments,” and then “search for authority either to sustain or reject his position.” *Id.*, p. 15, citing 457 Mich 232, 243 (1998). Based on this and other reasons, DTE contends that the Staff’s proposed figure for working capital should be adopted for use in this case.

The ALJ agrees with the Staff and the utility that $1,021,860,000 should be used as the working capital figure in this case when computing DTE’s net rate base. This conclusion is based on Mr. Nichols’ testimony, the concurrence of the company with regard to that figure, and the previously-noted fact that (under Michigan law, as expressed in *Wilson v. Taylor* and elsewhere) failure to brief an argument is tantamount to abandoning it. As a result, the ALJ recommends that the Commission adopt the working capital figure computed by Mr. Nichols and sponsored by the Staff.\(^{10}\)

\(^{10}\) Even if the ALJ did believe that the various components of the Attorney General’s requested $61.3 million working capital adjustment should be considered in this proceeding, the evidence and argument offered in opposition to that proposed reduction to Customer Accounts Receivable, downward adjustment to DTE’s Prepaid Other Post Employment Benefits (OPEB) Asset, and increases in both Interest Payable and Income Tax Payable, appear more than adequate to justify their rejection. See, DTE’s reply brief, pp. 15-17, citing: Exhibit A-27, Schedule T2; Exhibit A-9, Schedule B5.1, p. 1; and 2 Tr. 379-380, 513, and 517-518.
C. Conclusion

In light of the discussion and recommendations set forth above, the ALJ finds that DTE’s total rate base for use in this case should be set at $3,712,843,000 on a jurisdictional basis. This level, which begins with the rate base figure derived from the various positions advanced in the utility’s reply brief and delineated on Attachment A of that reply brief, p. 2, and which also incorporates the above-mentioned findings and recommendations, is computed as follows:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Utility Plant (per Attachment A, p. 2)</td>
<td>$3,739,371,000</td>
</tr>
<tr>
<td>Less: Contingency Cost Disallowance</td>
<td>($9,380,000)</td>
</tr>
<tr>
<td>Less: Revenue Protection Program Reduction</td>
<td>($1,490,000)</td>
</tr>
<tr>
<td>Less: Gas Reconversion Cost Adjustment</td>
<td>($4,072,000)</td>
</tr>
<tr>
<td>Less: GHIB Adjustment</td>
<td>($11,871,000)</td>
</tr>
<tr>
<td>Plus: Cap. Ex Adjustment Impact on Accumulated Depreciation</td>
<td>$285,000</td>
</tr>
<tr>
<td>Total Rate Base:</td>
<td>$3,712,843,000</td>
</tr>
</tbody>
</table>

The computation of the above figure is set forth in detail on Attachment A to this PFD, which begins with the figures set forth in the utility’s reply brief, and then adjusts them to correspond with those that have been derived/adopted in the course of this PFD. Nonetheless, the ALJ fully recognizes that adjustments to such things as the accumulated provision for depreciation, depreciation expense, CWIP, AFUDC, etc., are often interrelated, and that a change to one element can necessitate an unforeseen change to another. Such changes may be appropriate as a result of the above-described recommendations. Obviously, the parties may address these potential adjustments in their exceptions and replies to exceptions.
V.

CAPITAL STRUCTURE, COST OF CAPITAL, AND RATE OF RETURN

As noted in previous Commission orders, the criteria for establishing a fair rate of return for utilities like DTE stems from the decisions issued by the United States Supreme Court in Bluefield Water Works Co. v Public Service Comm. of West Virginia, 262 US 679 (1923), and Federal Power Comm. v Hope Natural Gas Co., 320 US 591 (1944). In those cases, (generally referred to as “Bluewater” and “Hope”), the Court made clear that when establishing a fair rate of return for a public utility, consideration must be given to both customers and investors. As stated in past rate cases concluded before this Commission, the rate of return “should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise.” December 23, 2008 order in Case No. U-15244, p. 12. Still, the Commission went on to note, any determination of what is fair and reasonable “is not subject to mathematical computation with scientific exactitude but [rather] depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use.” Id., [citing Meridian Twp. v City of East Lansing, Mich., 342 Mich 734, 749 (1955)].

With these time-tested principles in mind, we turn to the factors forming the basis for what rate of return should be adopted in this particular proceeding. Specifically, to reasonably estimate DTE’s revenue requirement, it is necessary to select a rate of return to be applied to the utility’s rate base. This involves a two-step process. The first is determining the appropriate capital structure, that is, the
relative percentages of debt, equity, and deferred income taxes used to fund the utility’s overall operations. The second is determining the proper cost rate for each component of the capital structure.

Despite differing views regarding what rate of return should be established in this case, the parties appear to have been able to reach agreement (or, at minimum, failed to express objection) concerning several components of DTE’s capital structure and the respective costs of the utility’s sources of capital.

As a result, the only areas of dispute in this regard that must now be addressed concern (1) the correct capital structure to be adopted in this matter, which involves resolving a dispute between the Attorney General on the one hand, and both DTE and the Staff, on the other, (2) the appropriate return on common equity, which entails the greatest difference of viewpoints and the largest volume of both testimony and argument offered by the parties, and (3) the long term debt rate that is now agreed upon by the utility and the Staff, but which differs from a very slightly lower rate proposed in the Attorney General’s brief. Each of these three issues is addressed below.

11 While DTE claims that its weighted, after-tax overall rate of return should be 6.02% (reached by starting at 6.04%, but subsequently adjusting its initial figure to incorporate several changes proposed by the Staff), the Attorney General suggests using 5.57%, while the Staff asserts that 5.73% should be adopted. See, DTE’s reply brief, p. 17; Attorney General’s initial brief, p. 54; and Staff’s initial brief, p. 27.

12 Notwithstanding the fact that (because they were based on the parties’ respective “as-filed cases”) the specific dollar values attached to each component of DTE’s capital structure may vary from what is recommended in the PFD, as well as what is actually approved by the Commission’s final order in this case, those percentages should remain relatively consistent throughout, thus allowing the utility, the Staff, and any interested party to make the final calculation once the Commission issues its order.

13 One of the other issues that usually causes “dissention in the ranks,” so to speak—in general rate cases like this is the cost rate to be applied to the utility’s projected short-term debt. Here, in addition to agreeing that DTE’s short-term debt balance for the test year should be
A. Capital Structure

As indicated above, an issue has arisen in this case with regard to the most appropriate capital structure to be applied to the projected test year. This dispute relates to the ratio of common equity to long term debt (as well as the specific levels of each) that should be assumed for use in this case, including whether and how these various capital structure balances should be adjusted to reflect the effects of bonus depreciation.

Based on an analysis conducted by Edward Solomon, the Assistant Treasurer and Director of Corporate Finance, Insurance, and Development for DTE’s parent company (DTE Energy), the utility asserted that its permanent capital structure should consist of 52% common equity and 48% long-term debt, “which is consistent with the Company’s current and planned capital structure.” DTE’s reply brief, p. 18, citing Exhibit A-11, Schedule D1, as well as 2 Tr. 133-136, 148, and 150-151.

Relying on testimony provided by Kirk D. Megginson, a Financial Specialist in the Revenue Requirements Section of the Commission’s Financial Analysis and Audit Division, the Staff agreed with the utility’s position regarding the adoption of a 52/48 percent structure for the company’s permanent capital. See, Staff’s initial brief, pp. 27-28, citing Exhibit S4, Schedules D-2 and D-5, as well as 3 Tr 1184-1185. However, again based on testimony offered by Mr. Megginson, the Staff asserted that, due to an extension regarding the allowed use of bonus depreciation, approximately $138 million, the only parties to weigh in on the matter of what that debt’s cost should be ultimately agreed that 1.54% would be the appropriate cost level to use in setting the utility’s future rates. See, DTE’s initial brief, p. 9, as well as Staff’s initial brief, p. 29.
the common equity balance proposed by DTE should be reduced by approximately $4.5 million to roughly $1.439 billion. See, Staff's initial brief, p. 28, citing 3 Tr. 1184-1185. For the same reason (namely, the extension of bonus depreciation), the Staff claimed that the long-term debt balance should also be reduced by about $4.5 million to approximately $1.329 million. See, Id. In conjunction with these two changes, Mr. Megginson went on to note that a corresponding $9 million increase in DTE's initially-proposed net deferred income tax balance for the test year would also be appropriate, thus raising that figure to approximately $801 million. See, 3 Tr. 1184, citing Exhibit S-12.2.

"For the purposes of narrowing the number of contested issues in this proceeding," the utility has now elected to "adopt the capital structure changes" proposed by the Staff as needed to reflect "the extension of bonus depreciation." DTE's reply brief, p. 18, citing Attachment A, p. 4). This appears to correspond with Staff's proposed treatment, which can be found in Appendix D of its initial brief.

In contrast to both the utility and the Staff, and based largely on testimony offered by Mr. Coppola, the Attorney General recommended reducing the utility's proposed common equity balance and increasing the company's long-term debt balance to a level where the company would have a 50/50 permanent capital structure. See, Attorney General's initial brief, p. 52, citing Exhibit AG-25. According to the Attorney General, such an adjustment is necessary in light of the fact that, because DTE "is essentially a pure gas utility, there is no reason to increase equity levels" to the extent proposed by the company (by way of an assumed large capital infusion during 2016). Id., p 53.
The ALJ does not find the position taken by the Attorney General on this particular matter to be persuasive. As specifically pointed out in rebuttal testimony offered by Mr. Solomon, DTE is not increasing its relative equity levels (as asserted by the Attorney General’s witness), but rather is simply making the investments necessary to maintain its existing 52% common equity level--as it has essentially done each year since 2009--in order to retain its current credit ratings. See, 2 Tr. 150-151. A lower credit rating or ratings would likely result in increased debt costs, and thus higher rates for the utility’s customers. Moreover, Mr. Coppola provided no clear testimony regarding whether moving to the 50/50 ratio he suggested would actually benefit DTE’s retail customers. As a result, the ALJ recommends that the Commission reject the Attorney General’s proposal and, instead, adopt the 52/48 percent capital to debt ratio for DTE’s permanent capital structure that has been proposed and supported by both the utility and the Staff. In addition, it is recommended that the actual dollar values suggested by the Staff (which adjust the common equity and long-term debt levels to be used in computing the company’s final cost of capital, based primarily on the extension of the previously-mentioned bonus depreciation) be adopted for use in this case. This includes the Staff’s suggested increase of roughly $801 million to DTE’s initially-proposed deferred income tax balance for the test year.

As a result, the ALJ recommends that the permanent capital structure to be used in this proceeding be predicated on a 52% to 48% equity to debt ratio, as suggested by both DTE and the Staff. In this instance, and as represented by the Staff (including the relatively small changes resulting from the extension of bonus
depreciation), the 52% equity ratio would represent a projected common equity balance of $1,438,768,000 and the 48% debt ratio would result in a long-term debt balance of roughly $1,329,379,000. See, i.e., Staff’s initial brief, p. 30, and Attachment D to that brief, lines 1 and 2. In addition, the ALJ recommends adopting the above-mentioned deferred income tax balance of $800,814,000, as well as the short-term debt balance of $137,815,000 suggested by the Staff, neither of which were significantly opposed in this case. See, Id., as well as Attachment D, lines 4 and 7. Finally, based on no objection by any of the parties to this proceeding, as well as for the sake of consistency, the ALJ recommends that the Commission include in its adopted capital structure $8,918,000 in customer deposits, $3,869,000 in other interest bearing accounts, $1,495,000 in long-term debt associated with JDITC, and $1,618,000 in JDITC-related common equity. See, Staff’s Attachment D, lines 5, 6, 9, and 10; See also, DTE’s initial brief, Attachment A, p. 4, lines 27, 29, 31, and 32.

The adoption of all of the above recommendations results in a test year projected capital structure totaling $3,722,676,000. See, Id., at lines 12 and 37, respectively.

**B. Cost of Common Equity**

A utility’s cost of common equity is the return that investors expect, or--more accurately--require, in order to provide the utility with capital for use in its various operations, generally referred to as the return on equity (ROE). The cost of this capital essentially represents an opportunity cost; in order to induce investors to purchase common stock or bonds, there must be the prospect of receiving earnings
sufficient to make the investment attractive when compared to other investment opportunities.

When a utility stands alone and its common stock is publicly traded, direct approaches can be applied to accurately estimate a fair rate of return on the utility’s common equity. However, the process becomes more complicated when the utility is a subsidiary of a holding company, as is the case with DTE. Because the stock of a subsidiary is not publicly traded, expert witnesses generally resort to indirect or proxy approaches to estimate the utility’s cost of common equity. In the present proceeding, three witnesses took on this task, one each on behalf of DTE, the Staff, and the Attorney General. In addition, and although it did not offer its own witness on this issue, ABATE evaluated the information provided by the other parties’ witnesses in presenting its analysis of what the Commission-approved ROE should be.

The utility’s primary witness concerning this issue was Michael Vilbert, Ph.D, a Principal of the Brattle Group, and whose work with that firm concentrates on financial and regulatory economics. See, 2 Tr. 175. According to Dr. Vilbert, the most reasonable ROE to be authorized by the Commission in this case would be 10.75%, which—although being above the average he computed for similar local gas distribution companies of 10% to 11%—reflects the fact that, at least according to assertions by both Mr. Solomon and himself,¹⁴ DTE’s financial and business risks

¹⁴ Specifically, it appears that Messrs. Solomon and Vilbert base their respective assessments on assertions to the effect that: (1) “the metropolitan Detroit and Michigan economies have been among the weakest economies” in the country; (2) “Michigan’s manufacturing and automobile industry base, although rebounding off of historical lows, remains under stress;” and (3) that “Detroit’s high unemployment rate, high poverty level, and declining population” serve to increase the business risk that DTE faces. 2 Tr. 143; See also p. 20 of DTE’s initial brief, fn. 30.
are higher than those of the six proxy companies used in his analysis. 15 See, 2 Tr. 143, 179, and 206-208.

Mr. Vilbert essentially conducted two separate financial analyses with regard to those six gas distribution utilities, estimating the ROE for each of them by using the Risk Positioning methodology—which is generally referred to as the Capital Asset Pricing Model (CAPM), adjusted for what he refers to as its “well documented empirical deficiencies”—along with the Discounted Cash Flow (DCF) Model. See, DTE’s initial brief, p. 22. He then combined the ROE estimates from both models with market value and capital structure figures, debt costs, and preferred stock information relating to his six proxy companies to “compute each company’s overall cost of capital (i.e., its after-tax weighted-average cost of capital, or ATWACC).” Id., citing 2 Tr 177, 209. This produced what DTE says is a “sample average ATWACC for each cost of equity estimation. See, Id.

According to the utility, Dr. Vilbert then reported the companies’ respective ROEs “consistent with the sample’s average estimated ATWADD as if the sample’s average market-value capital structure had a 52% equity ratio.” Id. According to DTE, the best estimate of the range of ROEs for gas utility companies having an “average business risk” and a capital structure with a 52% equity ratio is between 10% and 11%; however, the company continues, based on its witness’ assertion that DTE has a higher risk than the average gas utilities in its proxy group (for the reasons set forth in footnote 13, supra), Dr. Vilbert recommended an ROE of

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15 These six proxy companies, as well as their respective annual revenues, percentages of regulated assets, market capitalizations, and credit ratings from Standard and Poor’s (S&P), are identified in the chart provided by Dr. Vilbert and reflected on 2 Tr. 206.
10.75%. See, Id. This is based, Dr. Vilbert concludes, on “the financial risk inherent in a 52% equity ratio for [DTE], the sample ATWACC estimates, and the relative risk of [DTE] compared to the sample” (a/k/a the six-member proxy group). Id., pp. 22-23, citing 2 Tr. 179, 208-209, and 223-224. In light of its witness’ testimony, the utility contends that its ROE should be increased from its current level of 10.5% to 10.75% for the test year in question. See, DTE’s initial brief, pp. 21 & 30, and its reply brief, p. 31.

In contrast to DTE, the Staff recommended adopting an ROE of 10.00%, which represents the highpoint of the 9.00% to 10.00% range provided by its witness with regard to the appropriate cost of common equity, Kirk Megginson, a Financial Specialist in the Revenue Requirements Section of the Commission’s Financial and Audit Division. See, Staff’s initial brief, p. 30, and 2 Tr. 1177, 1186. According to Mr. Megginson, his analysis began by identifying five criteria designed to ensure that the members of the proxy group he used in estimating DTE’s ROE was highly representative of the utility itself. These criteria were that: (1) each utility had to have net plant greater than $2 billion, but less than $10.0 billion, to better compare in size and footprint to DTE Energy’s gas division; (2) each company had to derive 50% or more of its revenues from regulated gas service; (3) each utility had to have an investment grade rating within three notches of DTE’s from the two primary rating agencies, namely S&P and Moody’s; (4) each company had to currently be paying dividends to its shareholders; and (5) companies that were currently involved in mergers or corporate buyouts should be excluded. See, 3 Tr. 1188.
Based on those criteria, which appear somewhat narrower than Mr. Vilbert’s, he assembled his own list of six gas utility companies to use as the proxy group, which is set forth on Exhibit S-4, Schedule D-5, p. 2. Mr. Megginson then pointed out that his proxy group’s average credit rating from S&P is “A,” which is equivalent to that of DTE; however, he went on to note that the group’s average credit rating via Moody’s was approximately two notches below DTE’s. See, Id. Mr. Megginson further stated that, as of March 2016, the average allowed ROE for this group was 9.789%, which is slightly below what he and the Staff are recommending for DTE in this case. See, 3 Tr. 1189. Moreover, Mr. Megginson stated that, as reflected on Exhibit S-4, Schedule D-5, p. 4, the ROE for the proxy group he used in this proceeding had an average ROE during the period of 2011 through 2015 of only 9.609% (whereas DTE was allowed 11.60% during that same period). See, Id.

Mr. Megginson employed several models in conducting his analysis, most of which closely matched those relied upon by DTE’s witness. Specifically, he used the DCF model (which produced an average estimate of 8.90%, and a median estimate of 9.01%), a CAPM model (which provided an average estimate of 8.93%), and a Risk Premium model (resulting in a range from 8.01% for A-rated bonds to 8.34% for BBB-rated bonds). See, 3 Tr. 1190-1196. In addition, Mr. Megginson testified that he:

Reviewed the authorized rate of return decisions for natural gas utilities rendered by other State Commissions across the country for 2014-2015. The average authorized ROE from those decisions was 9.74%. [He] also reviewed a March 17, 2016 report from SNL’s Regulatory Research Associates that stated that the average ROE for gas in the United States in 2015 was 9.60%. [Moreover], the ROE authorizations appeared to decline from 2014 to 2015.
3 Tr. 1197. Mr. Megginson went on to state that:

Based on the average DCF cost of equity estimate of 8.90% for the gas proxy group, the average CAPM equity cost of 8.93%, the risk premium cost of 8.09% and 9.48% for A-rated utilities from the historical and survey results and 8.76% and 10.15% for BBB-rated utilities, [and] taking into consideration the average authorized ROE of 9.78% for the proxy group, Staff believes that a cost of equity recommendation for [the utility] falls within the range of 9.00% - 10.00%, as highlighted in Exhibit S-4, Schedule D-5, page 14 of 14. Considering the Company’s current authorized ROE of 10.50% and taking into consideration the concept of gradualism, the Staff recommends the cost of equity of 10.00% in its overall cost of capital recommendation.

3 Tr. 1197-1198. Based on this testimony, as well as its analysis of that offered by other witnesses in this case, the Staff advocates for the adoption of 10.00% as the ROE approved for DTE for the test year in question. According to the Staff, that level of return is “not only reasonable, but quite possibly generous.” Staff’s reply brief, p. 5.

Based on testimony offered by its witness, Mr. Coppola, the Attorney General recommended setting DTE’s test year ROE even lower than that suggested by the Staff, ultimately concluding that an ROE of 9.75% should be adopted in this case. See, Attorney General’s initial brief, p. 67.

Mr. Coppola began his analysis by adopting the six-member proxy group used by DTE’s witness Vilbert. See, Id., p. 57 and 3 Tr. 1048. He then performed his own DCF, CAPM, and Risk Premium analyses. See, Id., p. 56. In addition, Mr. Coppola stated, he “considered the current circumstances in the Capital Markets,” as well as any “potential changes in the risk profile for [DTE] as a result of its gas business and the improving Michigan economy.” 3 Tr. 1048.
As described in detail by Mr. Coppola, his use of different financial inputs than those relied upon by Messrs. Vilbert and Megginson, as well imposing different levels of reliance on those inputs than those reflected in his counterparts’ respective analyses, produced results that varied substantially from theirs’. See, 3 Tr. 1047-1055. The results arrived at by Mr. Coppola, which are summarized on Exhibits AG-27, AG-28, and AG-29 for his DCF, CAPM, and Risk Premium analyses, respectively, were 9.78%, 8.93%, and 8.70%. See, Id.

Mr. Coppola went on to state that, as summarized on Exhibit AG-26, the three rates that his various analyses produced, when weighted accurately (by giving the DCF analysis a 50% rating, and applying a 25% rating to both of the others)\(^{16}\) result in an overall ROE for the utility of 9.30%. See, 3 Tr. 1057-1058. However, Mr. Coppola continued, he then increased his recommended overall ROE figure to 9.75%, based on his feeling that: (1) “unique risks and circumstances “ exist for DTE [largely because its service territory is “highly dependent upon the automotive industry,” as well as “how investors view those risks”]; (2) the extent to which, based on potential actions of the federal government with regard to interest rates, potential investors “anticipate higher interest rates, is uncertain;” and (3) the fact that the Commission “may be reluctant to set an ROE for the Company at the true cost of equity of 9.30%.” 3 Tr. 1058.

\(^{16}\) According to Mr. Coppola, the weighting that he employed was based on his belief that the DCF method is a “more reliable approach to estimating the cost of equity” than the other two methodologies. 3 Tr. 1057.
Consistent with Mr. Coppola’s analysis, the Attorney General asks that the Commission set DTE’s ROE “no higher than 9.75% in this case, as a gradual transition to the true cost of equity.” Attorney General’s initial brief, p. 69, citing 3 Tr. 1058.

Although not offering a witness regarding the general issue of DTE’s cost of capital, ABATE essentially asserts that the utility’s ROE should be set at a level below the 10% figure proposed by the Staff (and thus, one would clearly assume, lower than the utility’s proposed level of 10.75%). See, ABATE’s reply brief, p. 2. ABATE’s assertion is based on the fact that, of the results arising from the various analyses performed by Staff witness Megginson, only one produced an ROE figure above 9.44%, while a majority came in below 9.00%. Id. ABATE therefore recommends that the Commission refrain from adopting any ROE level in this case above the 9.75% level proposed by the Attorney General. See, Id., p. 3.

In reviewing the various analyses presented by the witnesses, and in considering the arguments presented by the parties, it is worth remembering that utility regulators have long recognized that no precise mathematical formula exists for determining the appropriate ROE to be adopted in any one case. That being said, the record clearly indicates that DTE’s request to increase its ROE to 10.75% is excessive. Instead, the ALJ finds that the 10.00% ROE discussed by Mr. Megginson and recommended for use by the Staff should be adopted. This conclusion is reached notwithstanding DTE’s assertion that the Staff’s proposed
Specifically, the ALJ finds that the utility’s proposal should be rejected for the following five reasons.

First, because authorized ROEs appear to be dropping across the country for public utilities like DTE (See, 3 Tr. 1056 and 1197), and as the economy—both in Michigan and the U.S. as a whole—is improving (See, 3 Tr. 1056-1059), raising DTE’s ROE from 10.50% to 10.75%, as requested by the company, seems highly illogical. Generally, the larger the utility (and, thus, the greater its economic clout with regard to the investment market), the more beneficial the rates and terms offered by the lending community will be. Moreover, the Commission recently issued an order for a smaller (albeit, electric-focused) utility in the Upper Peninsula that adopted an ROE of 10.00%. See, the Commission’s September 8, 2016 order in Case No. U-17897, at pp. 19, 20, and 55. Therefore, in light of the fact that commission-approved ROEs (both in Michigan and across the country) appear to be declining to levels of 10.00% or lower, it appears that 10.00% is much more reasonable than the utility’s proposal of 10.75%

Second, and as specifically noted by Mr. Megginson, it seems that several of the numbers used in DTE’s ROE models were either themselves, or were based upon, inflated data points, which “unduly spiked the Company’s ROE estimates.” 3 Tr. 1198. Furthermore, it does seem that the utility’s reliance upon its “estimated CAPM” results as opposed to what would result from application of the usual CAPM

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17 Although the ALJ concedes that the record gives some credence to assertions by both the Attorney General and ABATE that an ROE of 10.00% may actually be too high, the theory of gradualism (directly espoused by the Attorney General’s witness, Mr. Coppola, and indirectly agreed to by both the Staff and ABATE), supports using the 10.00% figure in this case, which represents a 50 basis point reduction from DTE’s currently-approved ROE.
process (a change in methodology that even this ALJ has rejected in the past as "an unsuitable cost of equity model"), is highly suspect. 3 Tr. 1198.

Third, DTE’s requested 10.75% ROE is clearly at odds with both the structure for rate cases established as a result of Act 286 and DTE’s progressively improving credit rating. With regard to the former, and as both stated in an earlier PFD authored by this ALJ and quoted by Mr. Megginson:

Act 286 (1) allows Michigan utilities to use projected test year revenues, expenses, and sales volumes in support of any requested rate increases, (2) provides for the possibility of self-implementation of all or part of a requested rate change within 180 days following submission of an application, (3) requires that the Commission issue a final order concerning the application within 365 days from its filing, and (4) restricts the amount of retail choice to 10% of a utility’s total sales. These [fairly recent] changes in Michigan’s regulatory framework . . . have tended to lean heavily in favor of the utilities and their investors by significantly reducing the risk borne by such companies in the past.

3 Tr. 1198-1199, citing the September 16, 2015 PFD in Case No. U-17735 at p. 88.

As for the later assertion, the Staff points out that DTE’s “solid” credit ratings from both S&P and Moody’s indicates that the utility “will not have a problem accessing capital markets on a reasonable, if not preferred, basis” to finance its infrastructure and capital investment programs. Staff’s reply brief, p. 5.

Fourth, using the six-member proxy group that the Staff proposed, and which was assembled based upon the five specific criteria set forth earlier, that entire group’s average authorized ROE stands at 9.78%, which drops to 9.74% when restricted to the ROE’s authorized by other states, using combined 2014-2015 results. See, 3 Tr. 1199. Moreover, the record indicates that the previously-mentioned ROE figure again drops to 9.60% when only 2015 figures are used.
See, Id. These fact suggest that the 10.00% ROE recommendation offered by the Staff is, as stated by Mr. Megginson, “actually more favorable” to DTE than the proxy group’s ROE, despite the fact that DTE’s “credit ratings are similar to [the Staff’s] proxy group’s S&P rating and two notches higher” than the proxy group’s rating from Moody’s. Id. As correctly explained by Mr. Megginson, this indicates that DTE is viewed as a safe, or even safer, investment than the members of the proxy group, which, he continues, “does not lend itself to a higher required ROE” than has been established, collectively, for those other utilities. Id.

Fifth, and possibly even more compelling, the significantly increased ROE that DTE is requesting in this case seems to ignore the existence of the Infrastructure Recovery Mechanism (IRM) that was initially approved by the Commission in early 2013 [and most recently adjusted in its June 6, 2016 order in Case No. U-16999], which provides for a surcharge that essentially guarantees cost recovery (including a return not only of, but also on) any utility investment in its main renewal program, the meter move out (MMO) program, and the company’s pipeline integrity program. As noted by the Staff’s witness on this issue:

The IRM provides the Company with surcharge revenue for planned work, which reduces cash flow and liquidity risk on a going forward basis with the program in place. This cash flow benefit is coupled with the simultaneous request for a new Gas Revenue Decoupling Mechanism (RDM) that proposes to eliminate the revenue cap on [DTE’s] current decoupling mechanism. Both the IRM and the RDM will reduce if not eliminate [DTE’s] risk in collecting its authorized revenue level, reduce or eliminate the Company’s risk of not earning its authorized ROE, and shift a substantial level of financial risk away from the Company and its shareholders and onto ratepayers. These beneficial factors do not lend themselves to a higher required ROE.

3 Tr. 1199-1200.
Based on the five factors discussed above, the ALJ finds that the Commission should set DTE’s authorized ROE at no more than the 10.00% recommended by the Staff, but should also strongly consider reducing the rate at some point in the future. This recommendation is based on the ALJ’s conclusion that DTE’s ROE should be closer to the lower rates arising from the analyses conducted by both Mr. Coppola and Mr. Megginson, but which further reflects the ALJ’s belief that the concept of gradualism would--at this point in time--better support the 10.00% rate ultimately recommended in this case. In no event, the ALJ concludes, should DTE’s request to increase its ROE as a result of this proceeding be approved.

C. Cost of Long-Term and Short-Term Debt

DTE originally proposed applying a long-term debt cost rate of 4.97% and a short-term debt cost of 1.84% when computing the utility’s overall test year cost of capital, based on testimony provided by Mr. Solomon. See, 2 Tr. 135, 144-148, as well as Exhibit A-11, Schedules D-2 and D-3. According to its own witness regarding these two cost factors--namely, Mr. Megginson--the Staff suggested applying cost factors of 4.98% and 1.54%, respectively, to the long-term and short-term debt ultimately included in DTE’s capital structure. See, 3 Tr. 1184-1186, as well as Exhibit S-4, Schedule D-1.

Subsequently, DTE elected to support the use of the Staff’s proposed debt cost rates, thus adopting the Staff’s suggestion to apply a weighted cost of long-term debt in the amount of 4.98%, as well as a 1.54% cost level with regard to short-term debt. See, DTE’s initial brief, p. 21, and DTE’s reply brief, p. 19.
According to the utility, because “no other party addressed long-term debt . . . [or] . . . short-term debt,” the above-stated cost figures should be adopted. See, Id.

In light of the record and the pleadings submitted by the various parties, the ALJ finds that DTE’s long-term debt cost figure should be set at 4.98%, and that the utility’s short-term debt rate should be set at 1.54%, as agreed to by both the Staff and the company. Each of these figures appear to be well supported by testimony provided in this case. See, 3 Tr. 1184-1186.

D. Conclusion

Based on the discussion set forth above, and because no disputes among the parties appear to exist with regard to the other cost elements (both with regard to their balance figures and respective rates), the ALJ concludes that—at least for purposes of this PFD—the most reasonable weighted cost of total capital to adopt for DTE’s projected test year is 5.73%. In so doing, it is recognized [as alluded to earlier] that this figure may need to be adjusted slightly at some point to reflect (1) the precise effect of any new depreciation rates approved subsequent to the issuance of either this PFD or the Commission order that is ultimately issued for this utility, (2) specific tax account levels that have been--or will possibly be--effected by further changes or additional extensions to the bonus depreciation structure, as well as alterations to other tax rules, and (3) other relatively minor items such as

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18 Although the Attorney General’s initial brief indicated that he accepted using the company’s slightly lower figure of 4.97% for long-term debt in this matter, no reason was expressed for adopting that particular level, and no response was offered to DTE’s election--as expressed in its initial brief--to switch to the Staff’s minimally different number. Moreover, the Attorney General neither offered testimony on this point nor provided argument in opposition to using the long-term debt cost figure of 4.98% initially suggested by the Staff’s witness, and now agreed to by the utility.
AFUDC. In any event, the ALJ recommends adoption of the capital structure and cost elements set forth on Attachment B to this PFD, which results in an overall weighted cost of total capital of 5.73%.

V. ADJUSTED NET OPERATING INCOME

In order to determine whether a revenue deficiency or excess exists for a regulated utility like DTE, it is necessary to establish that utility’s adjusted net operating income for the test year. Adjusted Net Operating Income (NOI) expresses, at least in the present case and in the most basic of terms, the difference between the company’s projected test year operating revenues and expenses. As a result, the first step in computing a company’s NOI is to forecast its overall sales level, and then convert that figure into the appropriate amount of expected revenue to be received during the test year through application of the utility’s proposed rates, adjusted for revenue received by other utility operations. The second step is to then determine the expenses that are expected to be incurred during the test year, and then subtract that total amount from overall revenues.

In this particular case, several issues that would likely have affected the computation of net operating income were resolved prior to the issuance of this PFD. For example, and similar to DTE’s adoption of the Staff’s proposed $9 million increase in deferred taxes discussed earlier with regard to the extension of bonus depreciation, as well as the company’s $428,000 reduction to net plant to reflect a related offset to construction in the form of non-municipal demolition fees (See, 2
In the present case, DTE initially asserted that its NOI was expected to decline from $178.8 million in the 2014 historical test year to $113.7 million in the projected test year. See, 2 Tr. 329, 333, 337, and 483, as well as Exhibit A-10, Schedule C1. The utility asserted that this expected decline was primarily driven by anticipated increases in operating costs due to inflation, growth in net plant, and “a higher shared net asset charge for new plant” with its sister company, DTE Electric. DTE’s reply brief, p. 31. In addition, the company assumed that its overall gas revenues would drop due to the replacement of its existing IRM surcharge with one that was significantly smaller, decreased gas sales, and lower midstream revenues. See, 2 Tr. 483, and Exhibit A-10, Schedule C1.1. However, as set forth in its reply
brief, DTE subsequently agreed to NOI-related adjustments that served to increase its initially-projected test year NOI to $116,666,000. See, DTE’s reply brief, Attachment A, p. 3.

In contrast, the Staff claims that DTE’s actual test year NOI will be $139,864,000. See, Staff’s initial brief, p. 40. The dispute between the utility’s estimate and that provided by the Staff begins with a difference in the heating values that each of them projected for the test year, which is an issue that was resolved in favor of the Staff earlier in this PFD (where it was recommended that the Commission adopt the Staff’s estimate of 1045 Btu per Mcf). However, other differences between these parties concerned matters relating to the appropriate level of test year operating revenue to be adopted in this case, as well as: (1) the projected Operating and Maintenance [O&M] expense; (2) Administrative and General [A&G] expense expected for the test year; and (3) various infrastructure costs incurred to maintain safe and reliable service. All of these issues are addressed below.

A. Sales and Operating Volumes, and Corresponding Revenue Forecast

Relying on a 15-year normal weather basis (which, although a divergence from the utility’s past use of a 30-year average, was not opposed by the other parties), DTE contends that its test year sales volumes will be 147.1 Bcf for the projected test year. See, DTE’s reply brief, p. 32. According to the utility, the fact that this figure represents a 14.0 Bcf reduction from historic levels simply reflects the impact of “conservation and increasing heating values,” which was “partially
offset by gains in the number of customers."

See, DTE's reply brief, p. 32. This figure (and its related revenue data) was based on testimony offered by Robert Feldman, DTE's Director of Gas Sales and Marketing. See, 2 Tr. 582-666. When coupled with "other revenues" expected by the utility, and as described below, the company now asserts that $774,563,000 should be adopted as its total operating revenue for the projected test year. See, DTE's reply brief, Attachment A, p. 3.

Pointing to testimony supplied by his witness, Mr. Coppola, the Attorney General contends that DTE's proposal relies upon an unfounded assumption that, due to expected energy conservation arising from its Energy Optimization (EO)

19 In the course of that testimony, Mr. Chapel also discussed the special contract between DTE and Exelon Energy Company (Exelon), and noted that it was entered into to "mitigate concerns raised by both the Staff and Federal Trade Commission." 2 Tr. 565. As a result of that agreement, all Exelon customers (who previously were customers of DTE) were removed from the utility's sales forecasts because they now receive their gas service from Exelon. See, 2 Tr. 566. None of the parties opposed the company's proposed treatment of this matter.

In addition, Mr. Chapel proposed the adoption of $3.72/Mcf as the average jurisdictional cost of gas rate for the projected test year, which covers parts of two GCR periods. See, 2 Tr. 567. The Staff, using more recent data from the New York Mercantile Exchange (NYMEX) computed an average cost of $3.6089/Mcf. See, 3 Tr. 1232-1235. The ALJ finds that the Staff's figure, which is based on more up-to-date NYMEX figures should be adopted for use by the Commission in this case.

20 These EUT customers are generally large volume commercial and industrial gas users who elect to purchase their gas supplies directly from a third-party producer/supplier, and then contract with DTE to simply transport that gas to their various facilities through the utility's pipeline system.

21 Mr. Feldman also testified regarding the general treatment of revenues expected to be received as a result of several long-term contracts (including some special contracts), pointing out that the methodology he suggests be followed in this case is consistent with that adopted by the Commission in DTE's previous gas rate cases. See, 2 Tr. 602.
program, customers’ gas purchases will “decline at an annual rate of 0.75% compounded over the time period from 2015 to the projected test year ending October 2017.” Attorney General’s initial brief, p. 8. According to him, this assumption is “not realistic,” and:

The assumed energy conservation rate reflects the goals of the EO program and not a demonstrated rate of conservation. Furthermore, the Company is not able to distinguish the EO program rate of energy conservation from the on-going rate of conservation that all customers continue to experience. In effect, it is somewhat duplicative to include in the forecast model both the assumed annual rate of 0.75% from EO energy conservation and the on-going overall rate of conservation already reflected in the [utility’s] historical gas usage.

Id. Based on these assertions, the Attorney General set forth what he believes is a “more realistic” forecast of DTE’s gas sales during the projected test year. Id. This forecast, which he claims reflects a more accurate gas usage decline of only 0.2% to 0.4% annually (as opposed to the 0.75% level used by the utility), and which also acknowledges the “incremental sales for 2016 and 2017 from the addition of new customers forecasted by [DTE],” leads to forecasted sales of 157.9 Bcf for the November 2016 through 2017 projected test year. See, Id., p. 9, citing Exhibits AG-1 and AG-3. In addition, the Attorney General (once again relying on testimony offered in this case by Mr. Coppola) requests that the EUT gas transportation figures proposed by the utility be increased from the company’s suggested level of 119.9 Bcf to a more realistic level of 134.2 Bcf. See, Id., pp. 10-11. Based on the levels of both gas sales and transportation volumes that Mr. Coppola estimated would occur during the test year, which significantly exceeded those predicted by DTE, the Attorney General asks that projected revenue be increased by $33 million over the level projected by the utility. See, Id., pp. 11-12, citing Exhibit AG-5.

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However, the Attorney General further asserted that the “the Company’s forecasted revenues for Loan and Exchange services for the future test year should be removed from the revenue requirements” set in this rate case, and instead “included as credits in the [utility’s] GCR cost of gas beginning with the month following [the issuance of] “a Commission order” in this proceeding. Id. p. 16. Should the Commission take all of these actions, which the Attorney General recommends, he contends that “the Company’s forecasted revenues should be increased by $27,667,739,” which would reduce the utility’s jurisdictional rate increase by the approximately same amount. See, Id., p. 17; See also, Attorney General’s reply brief, p. 17. Based on DTE’s total general sales revenue figure of $774,563,000, the Attorney General’s proposed increase would elevate that figure to $802,230,739.

In making his recommendation, the Attorney General supported numerous changes to the utility’s forecast of “off-system and transportation revenue,” which the company projected to be about $74.4 million. Of the four components encompassing this revenue area (i.e., contract storage, park and loan services, off-system transportation, and energy services), he took specific issue with the second and third. Specifically, based on testimony from his witness, the Attorney General claims that the forecasted revenue arising from park and loan service was--due to the company’s use of only a 3-year versus a 5-year estimation period--understated by $78,000 (the difference between DTE’s forecast revenue of $7,280,000 and the Attorney General’s estimated level of $7,358,000). See, Attorney General’s initial brief, p. 13. As for off-system transportation, the Attorney General stated that
although some level of reduction may be justified, the utility’s proposed $6.6 million reduction from actual 2014 revenue figures (which were $34.2 million) to its currently proposed figure of approximately $27.6 million as being “too draconian.” See, Attorney General’s reply brief, p. 13. Moreover, because recent discovery responses updating DTE’s forecast of its off-system transportation revenues reflect its expected receipt of $32,504,000 for this area, he contends that the utility’s initially-proposed figure should be increased by $4,940,000, as reflected on Exhibit AG-7.

For its part, the Staff came up with a total revenue figure that fell between those offered by DTE and the Attorney General, namely $797,214,000. See, Staff’s initial brief, Appendix C, column (e). This was based upon $626,066,000 in expected income from the utility’s gas distribution activities, $76,579,000 derived from transportation and storage efforts performed for various parties, and $94,569,000 in other revenues. See, Id., line 25. Its basis for this total revenue figure, and how it was calculated, is set forth in detail on pages 43 through 49 of the Staff’s initial brief.

Based on the totality of the evidence provided in this matter, it is recommended that the Commission adopt the mid-ground revenue forecast suggested by the Staff in the amount of $797,214,000. This recommendation is based on the following three factors.

First, and as explained clearly by testimony offered by the Attorney General’s witness, DTE’s projected decline in general gas usage and revenue throughout its service area was, indeed, overstated, particularly in light of the continuing upturn in
Michigan’s economy. Moreover, and as accurately pointed out by the Staff, the utility’s projected number of customers both qualifying and signing up for its Residential Income Assistance (RIA) program [which, it appears, is actually trending down as of late] would, at least based on historical data, more likely be 100,000 or less, as opposed to the 120,000 customers projected by the company. See, 3 Tr. 1273-1274. In addition, the Staff’s upwards adjustment to DTE’s EUT revenue level for the projected test year, in the amount of approximately $1.8 million, would seem to make sense in light of the above-mentioned increase in the utility’s overall sales forecast for the test year. See, Exhibit S-6, Schedule C-3, line 2.

Second, as both the Attorney General and the Staff assert, the off-system transportation and storage level suggested by the company should be increased to include a more reasonable level of “park and loan” revenue that DTE can reasonably expect to receive during its projected test year. See, i.e., 3 Tr. 1001-1003. Using the five-year historical average (as opposed to the utility’s shorter examination) would, as mentioned earlier in this PFD, likely provide a more reasonable estimation of the company’s earnings during the course of its projected test year.  

22 On a related topic, ABATE argues that the Attorney General’s recommendation to assign the park and loan revenues as a credit to only GCR customers, as opposed to all utility customers (including GCC and transportation-only customers) should be rejected. See, ABATE’s initial brief, pp. 22-23. The ALJ disagrees. As correctly noted by Mr. Coppola:

The bottom line is that these midstream revenues generated for the use of gas purchased for GCR customers are being included in base rates. Therefore, the benefit of the Loan and Exchange revenue are being spread to other customers who are not paying the cost of the gas purchases. This is an unfair subsidy to other customer groups, such as Gas Choice customers and transportation customers,
Third, the ALJ finds that the Staff’s proposed net increase of $1.8 million to DTE’s Other Operating Revenue (OOR) projection is best supported on the record and should be adopted in this case. Because it appears only logical that at least some level of non-municipal cut and cap charge revenue will be recovered by the utility, regardless of what account it may ultimately be assigned to, the estimated $855,000 in such charges should be included as a component of miscellaneous revenues, as suggested by the Staff. See, 3 Tr. 1242. Also, in light of the ALJ’s holdings elsewhere in this PFD regarding the values assigned to Lost and Unaccounted for Gas (LAUF) and Gas-In-Kind (GIK) exchanges, the $6,000 increase suggested by the Staff should be made to the company’s GIK projection. Moreover, although the level of income that DTE receives from Grantor’s Trust on an annual basis is, it appears, quite volatile, that fact does not support ignoring its existence altogether, as the utility’s suggestion to project that income at $0 for the test year would effectively do. A more reasoned approach, and the one offered by Staff witness Olumide Makinde, a Departmental Analyst in the Rates and Tariffs Section of the Commission’s Regulated Energy Division, would be to use a five-year average of the Grantor’s Trust revenue received by the company, which is $1,176,000, as an addition to DTE’s projected level of OOR. However, as a counterpoint to the three above-recommended increases to DTE’s proposed OOR levels, the ALJ also finds that the Commission should reduce the utility’s projected revenue who do not pay for the cost of gas purchases that make Loan and Exchange service possible.

3 Tr. 1004. Based on this testimony, the ALJ finds that ABATE’s argument on this issue should be rejected, and that, as proposed by the Attorney General, the assignment of all park and loan revenue should go solely to the utility’s GCR customers.

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Inter-Company Notes Relievab le revenue figure by $237,000, to remove that level of interest earnings, which would be consistent to the treatment of this particular revenue with regard to the working capital figure adopted earlier. See, the Staff’s initial brief, p. 49, citing Exhibit S-12.4.

As a result, the ALJ recommends that the Commission adopt, for use in this proceeding, the total general gas operations revenue figure of $797,214,000, as is recommended by the Staff and reflected on Appendix C, line 25, column e, of the Staff’s initial brief.23

B. O&M, A&G, and Generally-Related Expenses

Although the parties’ witnesses who testified regarding various expenses that were included in DTE’s initial filing gave rise to a large number of disputes, that number has dropped significantly. This is based on decisions by those parties (particularly DTE) to concede certain issues, as well as the abandonment of other issues by various parties (which, as noted in footnote 4, is in compliance with the Court’s ruling in Wilson v. Taylor, supra).24 For purposes of streamlining this PFD, only the remaining nine expense-related issues will thus be addressed in detail.

23 In reaching this conclusion, the ALJ recommends rejecting the ALJ’s request to increase by approximately $3.4 million--as a component of OOR--the amount included in both DTE’s and the Staff’s overall revenue figures offered in this case with regard to the utility’s Appliance Service Program. See, Attorney General’s reply brief, pp. 16-17. Although this is a close issue, the ALJ finds that—at least in the context of this particular rate case—the best course of action would be to rely on the 2014 historical revenue figure, as opposed to simply applying “the average compound annual rate of increase from 2009 to 2015.” Id., p. 17.

24 With regard to potentially expense-related topics [some of which might only increase the costs of preparing and issuing reports by a negligible degree], apparently uncontested matters included such things as requests by either DTE or the Staff for: (1) revised accounting authority, (2) changes to leak repair and corrosion backlog documentation, (3) proposed injuries and damages expense levels, (4) the treatment of the ANR Alpena transportation contract, (5) costs arising from AFUDC, (6) exclusion of costs regarding accrued employee vacation time, (7) meter assembly check reporting requirements, (8) utility cybersecurity reporting, (9) the recovery of manufactured gas plant
1. **Test Year Expense Inflation Levels**

Although initially proposing to apply inflation adjustments to its various expense components of 1.80% for 2016 and 2.30% for 2017, DTE has now agreed to adopt the Staff’s suggested levels of 1.45% and 2.57%. See, DTE’s reply brief, p. 4. This would serve to reduce the utility’s projected O&M expense by approximately $4.9 million, as reflected on page 3 of Attachment A to DTE’s initial brief. However, the Attorney General proposes that no inflation adjustment should be made to historical expense levels. See, Attorney General’s initial brief, p. 26. In support of his proposal, he claims that “inflation has been negligible in recent months,” and that the company has shown the “ability to reduce costs in prior years and also more recently for 2014 to 2015.” Id.

The ALJ does not find the Attorney General’s proposal adequately supported by the record. As noted in rebuttal testimony provided on this issue by Theresa Uzenski, DTE’s Manager of Regulatory Accounting:

[Attorney General Witness] Coppola offers no support for his assertion that inflation has been negligible; nor does he provide any basis for assuming that future rates will be consistent with those in “recent months.” With respect to the cost reductions in 2015, the Company has already included a $15.4 million reduction in costs as a normalization of 2014. As described in by direct testimony on page 17, lines 7 through 15, weather in 2014 was colder than normal, providing an opportunity for one-time investment spending on operations and maintenance work.

2 Tr. 516. Based on the factors described by Ms. Uzenski, the ALJ recommends that the Commission reject the Attorney General’s “No Inflation” proposal and, instead, adopt the figures agreed upon by DTE and the Staff.

remediation expenses, (10) annual smart grid reporting metrics, and (11) approval of DTE’s proposed OPEB deferral mechanism.

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2. Staff’s Adjustment to Shared Asset Rent Expense

The Staff proposed a $1.2 million reduction to shared asset rent expense to align the rent expense projected in this case with rent revenue projected in DTE Electric’s concurrently-running rate case. See, Staff’s initial brief, p. 57. DTE agrees with that proposed expense reduction. See, DTE’s initial brief, pp. 9 and 41; see also, DTE’s reply brief, p. 46. In Contrast, Attorney General witness Coppola claimed that a $2.7 million reduction should be made to shared rent expense for the new “Customer 360 system” due to the fact that the system is not now expected to be operational until April 2017. 3 Tr. 1016. Based on the record, it appears that his proposed adjustment would be incorrect.

As reflected on Exhibit AG-15, and as noted by DTE witness Uzinski, the adjustment sought by the Attorney General would remove rent expense related to the “Customer 360 system” (which it currently appears will be operational in April 2017) covering the whole period from November 2016 through March 2017. However, she noted, the projected period ending October 2017 included only 10 months of the system’s annual expense (namely, for the period of January through October, 2017). See, 2 Tr. 515. Based on this testimony, the ALJ recommends that the Commission reject the ALJ’s figure, and adopt the $1.2 million adjustment agreed to by DTE and the Staff.

3. Pension and Benefit O&M Expense

By way of its initial filing in this proceeding, DTE offered testimony and exhibits regarding its test year pension and benefit O&M Expense, which the company projected as totaling $36,723,000. See, Exhibit A-10, Schedule C5.9, line
32; as well as 2 Tr. 855-932. Subsequently, and as mentioned above, the utility adjusted this figure to include suggestions by the Staff to reduce expenses by revising the level of expected inflation rates, exclude costs arising from accrued vacation, and to reject the recovery of ESRP-related expenses in this case. See, DTE’s reply brief, p. 46. By agreeing to those three adjustments, the company presently requests the adoption of $33,234,000 as the level of pension and benefit expense to be used in this case.

Notwithstanding the utility’s acceptance of a reduced overall cost figure for its pension and benefit expense reimbursement for the projected test year, two unresolved issues still exist. The first concerns expenses related to retirement costs. Specifically, the Staff’s request that, in addition to agreed-upon removal of the $795,000 which DTE asserts relates exclusively to its ESRP, the Commission direct the utility to likewise remove the entire $644,000 in expenses arising from the operation of its Supplemental Retirement Plan (SRP), which simply covers a larger, albeit lower level group, of company executives/employees. See, Staff’s initial brief, pp. 56-57. The second unresolved issue concerns the Attorney General’s assertion that active employee health care costs should be reduced by $2.8 million, which stems from his claim that the 7.5% projected annual healthcare inflation rate proposed by the utility is grossly excessive. See, Attorney General’s initial brief, pp. 28-29. According to him, a more appropriate rate of increase would be between 2.5% to 2.6% annually. See, Id.
With regard to the first issue, DTE reasserts arguments made in several previously-decided Commission cases regarding such things as the need to essentially work around the effect of the Internal Revenue Code’s strict limits on funding such programs within the range of qualified retirement plans because federal legislators wanted to constrain the cost to taxpayers of benefits which benefited only a limited number of high income employees. See, i.e., 2 Tr. 871. Moreover, it essentially contends, yet again, that (1) benefits of this nature are necessary to attract, retain, and motivate high-quality employees, and (2) they actually are simply part of the utility company’s employees’ total annual compensation. DTE’s reply brief, p. 51.

The ALJ disagrees with DTE on this point, and finds that (as with the $795,000 initially proposed for the ESRP and now removed by agreement of the parties), the $644,000 expense reduction proposed by the Staff with regard to the SRP should also be removed from the calculation of O&M/Administrative Expense. As noted by the Staff’s witness on this issue, BrianWelke, an Auditor in the Revenue Requirements Section of the Commission’s Financial Analysis and Audit Division, research shows that the Commission has not included SRP-related expenses like those whose recovery is sought in this case as part of a utility’s revenue requirement during at least the last decade. This is reflected by a review of the Commission’s December 23, 2008 order in Case No. U-15244, its January 11, 2010 order in Case No. U-15768, and its October 20, 2011 order issued in Case No. U-16472. See, 3 Tr. 1207. Rather, their recovery has been consistently disallowed on the grounds that those programs’ costs have not been
shown to be commensurate with the benefits that are ultimately provided to ratepayers. See, Id. While it is frequently asserted that the purpose of these plans is not to earn money for investors, merely including their respective costs as part of the utility’s O&M expenses (and then setting the company’s revenue requirement accordingly) would allow the company’s shareholders to benefit from each and every dollar spent on those programs. Because both the utility’s ESRP and SRP plans appear to be substantively the same as those consistently disallowed the previously noted Commission orders, the ALJ recommends that the Commission adopt the recommendation of the Staff to remove the projected $644,000 in SRP costs (as well as the $795,000 in ESRP costs discussed earlier) from DTE’s requested Pension and Benefit O&M expense for the test year in question.

Turning the second issue, namely the Attorney General’s assertion that--based on testimony offered by his witness (namely, Mr. Coppola), which used a three-year average--projected active employee health care costs should be assumed to increase at an annual rate of only 2.5% to 2.6%, a $2.8 million cost reduction, the ALJ does not agree with that claim. Notwithstanding Mr. Coppola’s apparent belief to the contrary, history suggests that the 7.5% rate proposed by DTE constitutes a more reasonable estimate. As noted by Jeffrey Wuepper, DTE’s Director of Compensation and Benefits, changes in the utility’s active healthcare expense outlays have ranged from a 2.4% decrease in 2013 to a 10.4% increase in 2014. See, 2 Tr. 929. This, he went on to testify:
Highlights that any single year’s experience is unlikely to be predictive of future years [with regard to healthcare costs]. While multi-year averages are often employed in the rate setting process to address volatile costs such as lost and unaccounted for gas [referred to as LAUF] volumes, the use of averages in that circumstance recognizes the inherent randomness and unpredictability of future [LAUF] gas volumes. In contrast, active healthcare expenses have a predictable long-term trend with short-term volatility. Thus, the 7.5% projected trend is a more reliable predictor of future active healthcare expenses than a short-term average.

See, Id. For this and other reasons expressed in Mr. Wuepper’s rebuttal testimony, the ALJ concludes that the use of the higher inflation rate proposed by the company is reasonable than that advocated by the Attorney General witness Coppola. As such, the ALJ recommends that the Commission reject the Attorney General’s request to reduce projected active employee healthcare costs by $2.8 million for the test year.

4. Employee Incentive Compensation Program Costs

For its executives and non-represented (a/k/a, non-union) employees, DTE proposed three incentive compensation programs for adoption in the test year, for which it seeks rate recovery of $11,152,000. See, 2 Tr 900. These consist of a pair of short-term programs, namely its Annual Incentive Program (AIP) and its Rewarding Employees Plan (REP), as well as its “Long-Term Incentive Plan” (LTIP). According to Mr. Wuepper, adoption of the two short-term programs would collectively increase the utility’s revenue requirement by $7,682,000, while the LTIP would necessitate and increase of $3,471,000. See, Id.

As asserted by DTE, its witness provided a detailed description of the design and mechanics of these plans, including the metrics to be used in tracking company performance, the methods applied for setting the utility’s performance targets, and
the conditions of payment to employees of incentive compensation. See, DTE’s initial brief, p. 49, citing 2 Tr. 892-900, etc. In this regard, DTE asserts that:

The performance measures included within these plans include both operating and financial metrics. The operating measures reflected in the short-term incentive plans relate to Customer Satisfaction, Employee Engagement and Operating Excellence, as appropriately customized for the specific business units. Within Customer Satisfaction are measures related to improving as measured by J.D. Power. Also included are measures related to improving customer service and reducing complaints to the Commission. Employee Engagement pertains to creating a highly motivated and productive workforce as well as improvements to workplace safety. Operating Excellence includes six measures. These measures relate to reducing the number of gas leaks, lowering [LAUF] gas volumes, improving gas compression reliability, enhancing gas damage prevention effectiveness, and the installation of additional remote control valves.

DTE’s reply brief, p. 52, citing 2 Tr. 892-898, and 921. Based on this and other testimony offered in this case, the utility contends that (notwithstanding assertions to the contrary by both the Attorney General and the Staff), the full $11,152,000 of “normalized historical test period expense” sought for incentive compensation should be granted in this proceeding. Id.

With regard to this issue, the Attorney General asserts that, as the Commission has done for much of the past decade, it should reject all recovery of both short-term and long-term employee incentive compensation programs, essentially on the grounds that the potential benefits to customers are either non-existent or fall far below the amount they would be required to provide to the company to cover the cost of those particular programs. See, Attorney General’s initial brief, pp. 32-44. Specifically, he asserts that, with regard to the two short-term incentive programs:
No matter how the Company tries to dress them up, the AIP and REP are heavily weighted toward achieving and rewarding financial measures that mostly benefit shareholders of [DTE'] parent company, DTE Energy. Half of the AIP and REP payout is expressly tied to achieving the earnings and cash flow goals of DTE Energy. And other measures including, but not limited to, those tied to employee engagement, employee safety, and operational excellence benefit the Company’s and DTE Energy’s bottom lines more than customers, or are [simply] basic requirements of running a business for which customers should not be charged extra.

Id., p. 37. Turning to the long-term program, he notes that the various metrics used to qualify for an incentive award from the utility are based on (1) “total return to DTE Energy’s shareholders,” via capital appreciation and dividends granted, (2) the “balance sheet health” of DTE’s parent company, and (3) and the actual ROE for DTE for the 2015-2017 period. Id., p. 43. As a result, the Attorney General continues, there are “no customer service or operating efficiency measures that directly tie the cost of this [long-term] plan to utility customers.” Id. Finally, he asserts that because incentive pay that is primarily based on tenure does nothing other than reward longevity, without any showing that it is tied to--or even intended to--improve an employee’s overall performance, the recovery of LTIP expense should not be allowed in this case. See, Id., pp. 43-44.

For its part, the Staff adopted what can best be described as a “middle-ground” position with regard to incentive compensation. Specifically, and based on testimony by its witness, Mr. Welke, the Staff asserted that, of the $11,152,000 included in DTE’s projected expenses with regard to incentive compensation, $7,745,000 should be excluded. See, 3 Tr. 1204. According to Mr. Welke, this is consistent with the most recent order issued by the Commission that dealt with this
issue in a DTE-related case (namely, the December 11, 2015 order in Case No. U-17767, concerning DTE Electric). In that order, Mr. Welke pointed out:

The Commission found that the portion of Incentive Compensation Expense that is tied to [corporate] financial metrics largely benefits shareholders, and that because of this, should not be paid for by ratepayers.

3 Tr. 1205. Here, he continued, a portion of the utility’s incentive compensation costs are, indeed, “tied to financial metrics,” such as operating earnings, adjusted cash flow, and earnings per share. Id. Based on these factors, and in keeping with the consistent rejection of arguments to the effect that “financial metrics are appropriate for inclusion within [a utility’s] revenue requirement,” the Staff asserts that the best course of action would be to exclude those costs, while concurrently allowing recovery of the remainder (which the ALJ calculates to be $3,407,000). According to Mr. Welke, this treatment would be consistent with the Commission’s order in Case No. U-17767, as cited above. See, Id.

While it may look to be at odds with the Commission’s most recent order as cited by the Staff, the ALJ simply does not find the testimony provided by DTE in this case to be sufficient to require ratepayers to underwrite the provision of incentive compensation (whether provided through the utility’s AIP, REP, or LITP programs) to its various executives and employees. Notwithstanding DTE’s efforts to show that its currently-proposed programs satisfy the Commission’s clear and long-standing requirements for cost recovery, the ALJ agrees most fully with the Attorney General (and his witness) with regard to this matter. Specifically, the ALJ finds (as asserted in the testimony provided by Mr. Coppola) that significant problems still exist regarding both (1) these programs’ overall structure, and (2) the
evidentiary presentation provided in an effort to support adopting the utility’s request.

First, as was correctly noted by the Attorney General’s witness, the Commission long refrained from including incentive-based income programs as part of a utility’s revenue requirement. This can be seen by a review of the Commission’s December 22, 2005 order in Case No. U-14347, its December 23, 2008 order in Case No. U-15244, its January 11, 2010 order in Case No. U-15768, and its October 20, 2011 order in Case No. U-16472. Second, reasonable concerns with regard to incentive conservation programs presented in the past have led the Commission to repeatedly state what it would specifically need to see with regard to both a particular program’s structure, and the evidentiary presentation supporting its adoption, before rate recovery of any related costs would be considered. Here, that does not appear to have fully occurred. As accurately noted by Mr. Welke and Mr. Coppola, a majority (albeit, not all, according to Mr. Welke) of the targets set for utility employees in order to earn proposed incentive plan payments relied upon financial metrics that tend to benefit DTE, its parent company, and shareholders, as opposed to its ratepayers. See, 3 Tr. 1022-1028; See also, 3 Tr. 1205. This is in conflict with what the Commission has required in the past.

The ALJ thus finds that DTE has, again, failed to adequately support requiring its ratepayers to bear the financial burden of its various employee incentive compensation programs, and recommends that the Commission exclude all recovery of the related $11,152,000 sought in this case.
However, should the Commission elect not to fully exclude the $11,152,000 sought by the utility for this expense item, the ALJ then would suggest—as a “fall back” position only—adopting the Staff’s proposal to deny the recovery through base rates of the $7,745,000 in projected incentive payments that Mr. Welke asserted were solely “related to financial metrics,” as opposed to customer-focused activities. 3 Tr. 1205. Doing so would be more in keeping with the result of the Commission’s December 11, 2015 order in Case No. U-17767. To do otherwise would seem to be requiring ratepayers to pay the company’s employees to merely take actions that they are already expected to perform in their respective roles as members of a regulated utility.

5. Uncollectable Accounts Expense

A utility’s uncollectible account expense (generally referred to simply as its uncollectible expense) represents the cost level that is recorded in the company’s income statement to reflect the portion of current sales revenue that is not expected to be collectible from its customers. Both the Generally Accepted Accounting Principles (GAAP) and the Commission’s Uniform System of Accounts (USOA) require that DTE currently recognize, on its income statement, that portion of each year’s revenues that will not be collected, at least in the normal course of its billing practices. As recognized by several of the parties, the level of uncollectable expense for any particular period is influenced by such things as the general vibrancy of the economy, the amount of energy assistance paid to customers in distress from state and federal agencies, regional unemployment levels, and
general inflation rates. See, i.e., DTE’s initial brief, p. 62, and Staff’s initial brief, pp. 51-52.

In this proceeding, DTE and the Staff agree that the most appropriate level of uncollectable expense that should be included in the utility’s total test year O&M expense should be approximately $44 million. See, DTE’s reply brief, p. 64.25 This figure essentially arises from use of the utility’s suggested three-year average of uncollectable expense, but also incorporates more recent data, as proposed by the Staff. See, Id.

In contrast, the Attorney General contends that the initial approach taken by DTE (and subsequently updated by the Staff) was “too simplistic.” See, Attorney General’s initial brief, p. 30. According to him, instead of using the three-year average of historical uncollectible expense that serves as the basis of the combined DTE/Staff cost figure, the Commission should rely on the “ratio of uncollectable write-offs to revenue over multiple years.” Id. “The resulting average ratio can then be applied to forecasted test year revenues to determine an appropriate forecast of uncollectable accounts.” Id. Employing this methodology (and adjusting it for expected savings based on the implementation of the company’s AMI program), the Attorney General asserts that the Commission should reduce the level of uncollectable accounts expense to $39.8 million. See, Id., pp. 30-31.

25 Although taking no position regarding the level of the uncollectible expense that should be adopted for use when calculating DTE’s revenue deficiency (should there actually be one), ABATE takes issue with the allocation of those costs proposed by the Staff, and--it appears--adopted by the utility. See, ABATE’s reply brief, p. 2. This matter will be addressed subsequently, in the portion of the PFD concerning cost allocation/rate design.
Based on the record and the arguments offered by the parties regarding both this and other issues, the ALJ concludes that the Attorney General’s assertion should be rejected, and that the uncollectable expense level of approximately $44 million (proposed by the Staff, and ultimately adopted by DTE) should be used in computing the rates arising from this case. This conclusion is based on the following two factors.

First, as noted by the company, the position espoused by the Attorney General on this particular issue appears to be at odds with other proposals set forth in his various briefs. As correctly noted on page 64 of DTE’s reply brief, the Attorney General (on page 5 of his initial brief) essentially “advocates for an increase in gas revenues for the projected test year,” but now “recommends using the Company’s projected distribution revenue to derive his uncollectable expense.” As noted by the utility, if the average net write-off percentage was applied to the Attorney General’s higher gas revenue figure, his overall level of uncollectable expense would also rise. See, DTE’s reply brief, p. 64.

Second, the uncollectable expense reduction related to the utility’s AMI program that Attorney General witness Coppola described (see, 3 Tr. 1019) does not appear to be supported by the record as a whole. As noted by the DTE’s witness on this issue, Robert Sitkauskas, who is the General Manager of the AMI Group for the company, the AMI-related figure used by Mr. Coppola in his calculations regarding his expected reduction in uncollectable expense was actually “an avoidable cost” number that Mr. Sitkauskas used in his “AMI cost-benefit analysis for the complete AMI project from inception to the 20-year life of each
module,” and, as a result, the “change in uncollectable expense is also cumulative year over year.” DTE’s reply brief, p. 64, citing 2 Tr. 301-302, and 833-834. As a result, it appears that the Attorney General’s witness incorrectly applied the entire 20-year cost savings from the AMI project (at least with regard to uncollectable expense) to the single test year upon which this case is focused.

Thus, the ALJ recommends that the Commission reject the Attorney General’s proposal and, instead, adopt—as the appropriate level of uncollectable expense used for setting rates in this case—the $44 million dollar figure agreed upon by DTE and the Staff.

6. LAUF, Company Use (CU), and GIK Expense

Although applying slightly different prices to them, in its initial filing (and as also reflected in its initial brief) DTE claimed that the Commission should accept 6.645 million cubic feet (MMcf) as its level of LAUF gas for the test year, “based on a five-year average” running from September 1, 2010 through August 31, 2015, which it further notes is “in accordance with the methodology” adopted by the Commission in the utility’s last three contested rate cases, and that “the Staff supported” in its most recently settled rate case. DTE’s initial brief, p. 65. As for CU gas, the company advocated adopting 2,500 MMcf as the volume to use in this case, which it contends is “reasonably consistent with the actual CU level during the

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26 As explained by DTE, LAUF essentially represents the difference between its booked sources and booked uses of gas, and is comprised of transmission system losses [generally metering losses] and distribution system losses [which tend to consist of a combination of gas theft, leaks, and metering losses]. See, DTE’s initial brief, p. 65, fn. 61. As for CU, the utility notes that these volumes are predominantly related to fuel used to operate and maintain DTE’s transmission and storage facilities, and comes in the form of gas used for its compressors, gas processing at its storage fields, and gate station heaters. See, Id., p. 65, fn. 62. Finally, the company notes that GIK is gas, expressed as a percentage of total system throughput, that is supplied by its various customers to offset CU gas, and sometimes includes LAUF gas. See, Id., p. 66, fn. 63.
2014 historical test year.” Id., citing 2 Tr. 405 and Exhibit A-12, Schedule E13. With regard to GIK, DTE recommends that: (1) the utility's current, authorized GIK rate of 1.116% that is being applied to its largest EUT customers [essentially, those transportation customers taking service via Rate XXLT] be reduced to 1.00%; (2) the existing 1.63% GIK adder applied to all of its off-system service rates likewise be reduced to 1.00%; and (3) the GIK adder applied to its other EUT customer classes [namely, those taking service on the company’s ST, LT, and XLT rates] be reduced from 1.66% to 1.41%. See, 2 Tr. 590-590, 640, 651, and 800-801, as well as Exhibit A-12, Schedule E17, line 18.

As for the Staff, it and DTE apparently agree that the appropriate level of LAUF gas to be used in this proceeding is 6,645 MMcf. See, Exhibit S-14, Schedule E10 [revised]. Also, it appears that only one issue separates the utility’s position regarding the appropriate level of LAUF, CU, and GIK expenses to be included in the computation of DTE’s rates in this proceeding from that accepted by the Staff, and that is that the Staff contends that the cost of gas for each of these three cost components should be priced at the same level. See, Staff’s initial brief, p. 50, citing 3 Tr. 1249. According to the Staff’s witness on this issue, David Isakson, a Departmental Analyst in the Rates and Tariff’s Section of the Commission’s Regulated Energy Division, pricing all three components discussed above “is consistent with how these volumes are valued in the GCR reconciliation process,” and as shown on Exhibit A-15 in the Company’s most recent GCR reconciliation filing, which he identified as Case No. U-17332-R. 3 Tr. 1249. As
reflected on Exhibit S-14, Schedule E10, this change in pricing would reduce DTE’s overall expense by $1,576,000. See, Staff’s initial brief, p. 50.

Although acknowledging that use of a five-year average (as proposed by DTE, and apparently adopted by the Staff) is the “accepted methodology” for projecting the volume of LAUF gas, the Attorney General asks the Commission to use a three-year average instead, which he claims would result in a $3.4 million reduction in LAUF costs. Attorney General’s initial brief, pp. 19-20. This request is based, in large part, on Attorney General witness Coppola’s assertion that the annual volume of LAUF gas is trending downward. See, 3 Tr. 1009-1010. Moreover, Mr. Coppola continued, the five-year average of LAUF gas should be abandoned in favor of his three-year structure because DTE has claimed to be taking steps to reduce the annual volume of LAUF gas. See, 3 Tr. 1009-1010.

ABATE agrees with the Staff’s assertion that all of this gas should be priced at the same level “regardless of the purpose for which it was used, or whether it was lost and not burned by [the utility’s] customers.” ABATE’s reply brief, p. 2. Nevertheless, ABATE goes on to support the Attorney General’s request to reduce DTE’s proposed level of LAUF gas expense by $3.4 million. See, Id., p. 3.

The ALJ finds that general logic, arguments offered in this proceeding, and the record assembled in this case support adopting the LAUF, CU, and GIK figures offered by the utility, but with the revisions suggested by the Staff (and ultimately supported by ABATE, at least in part).
First, it seems only appropriate that gas that escapes from DTE’s transmission and distribution systems, via leaks or otherwise, should be priced at the same level as the gas used to keep the utility’s system running, whether by its use to power compressors or by being injected as base gas to keep the company’s various storage facilities functioning at their optimal levels. It appears that no testimony was offered to specifically explain why a different price should be applied to such gas, and no explanation was offered regarding why the treatment in this rate case should differ from that generally provided in the utility’s GCR reconciliation cases.

As a result, the ALJ recommends that the Commission price all of the gas in question at the same rate [as suggested by both the Staff and ABATE], which has the effect of reducing DTE’s overall expense level by $1,576,000, as noted above.

Second, as correctly noted by the utility (and agreed to by the Staff), it appears that the five-year average of LAUF volumes, which was adopted by the Commission in each of DTE’s last four rate cases—the first three being contested rate proceedings, and the fourth being a settled case—should be used in this matter. Although advocating for use of the three-year average proposed by its witness, Mr. Coppola, the Attorney General concedes that the Commission usually relies on a five-year average for LAUF volumes. See, Attorney General’s initial brief, p. 20. Moreover, notwithstanding Mr. Coppola’s testimony to the effect that there is a trending decline in the utility’s volume of LAUF gas, historical data provided in this case shows that LAUF gas volumes for DTE tend to vary from one year to another,

27 In its reply brief, ABATE expressed support for the Attorney General’s proposal, but did not indicate the basis for taking that position. See, ABATE’s reply brief, p. 2.
with no particular pattern. Specifically, the record indicates that that volumes for LAUF gas dropped by 0.58 BCF (or 10%) between 2012 and 2013, increased by 0.64 Bcf (or 12%) between 2013 and 2014, and then decreased by 0.31 Bcf (or 5%) between 2014 and 2015. See, 2 Tr. 423. As a result, the ALJ recommends that the Commission adopt 6.645 MMcf as the appropriate level to use in the test year, as agreed to by DTE and the Staff.

Third, with regard to the two remaining issues, namely volumes and expenses related to CU and GIK, the only significant dispute concerns the Btu levels applied by the parties, which was resolved in favor to the Staff earlier in this PFD. Specifically, although DTE initially applied different prices for LAUF, CU, and GIK, it subsequently agreed to the Staff’s proposal to apply the same cost of gas to each. See, DTE’s reply brief, p. 67. None of the other parties appear to disagree with that proposed treatment. Thus, the ALJ recommends that the utility’s proposed volumes (albeit adjusted to reflect the change arising from the previous adoption of the Staff’s suggested Btu levels), as well as the Staff’s suggestion to price all three equally, should be adopted in this case.

7. Property and Other Tax Expense

DTE expects that it will owe a total of $72.2 million in property and other tax expense for the test year adopted for this case. See, Exhibit A-10, Schedule C1.1. According to the utility, this consists of property taxes, payroll taxes, and other tax expense, as well as the Commission’s assessment fees, as reflected on Exhibit A-10, Schedule A-10, Schedule C7. See, DTE’s initial brief, p. 68.
For its part, the Staff (based on testimony offered by Mr. Welke) proposes a property tax expense reduction of $6,431,000. See, 3 Tr. 1208. According to the Staff’s witness, this downward proposed property tax expense change is based on the fact that, “from 2011 through 2015, the Combined Average Growth Rate (CAGR)” for the utility’s property tax costs “has been 3.69% year over year.” Id. Applying the CAGR to the utility’s actual property tax expense for 2015, Mr. Welke notes, leads to the Staff’s suggested reduction in the company’s projected property tax expense. See, Id.

DTE objects to making the Staff’s property tax cost reduction on the grounds that “the CAGR method incorrectly assumes uniform increases in property taxes,” whereas “the actual change in property taxes varies from year to year.” DTE’s reply brief, p. 69. Moreover, the utility contends, application of the CAGR-based method suggested by the Staff ignores the effect on property tax of “the level of net capital additions and the type of assets placed in service,” as well as those that are retired from rate base. Id., p. 70. For this and other reasons, the utility asserts that the Staff’s proposed reduction to the company’s property tax expense figure should be rejected.

The ALJ disagrees with DTE, and finds in favor of the Staff on this issue for the following three reasons.

First, the methodology used by the utility to arrive at its projected property and other tax expense level for the test year has, when employed in the past, led to inaccurate (and inflated) results. For example, the record indicates that in the company’s most recent rate case (Case No. U-16999), the methodology currently
proposed by DTE resulted in an expense projection that turned out to be over $2 million higher than the actual tax costs incurred. See, 3 Tr. 1208. Similarly, application of the utility’s methodology appears to have projected a property tax expense for 2015 that is nearly $1.3 million higher than what was actually incurred. See, Id.

Second, as pointed out by Mr. Welke, the Staff’s CAGR-based projection methodology uses actual property tax and other tax expense information from the 2011 through 2015 period. See, 3 Tr. 1209. Those figures, which are derived from actual as opposed to projected costs, support a growth rate much closer to the Staff’s suggested 3.69% level than the 7.51% level employed by DTE. See, Id.

Third, the average change in property and other tax expense between 2011 and 2015, according to the utility’s own Exhibit A-24, Schedule Q1, is 3.85%. That growth rate is much closer to the 3.69% level proposed by the Staff for use in this rate case, and stands in stark contrast to the company’s assumed rate of over 7.5%.

Based on these and other factors, the ALJ recommends that the Commission adopt the Staff’s suggested growth rate (3.69%), and thus also adopt the corresponding $6,431,000 reduction to DTE’s projected property and other tax expense.
8. Federal, State, and Local Income Tax Expense

As with the utility’s accumulated provision for depreciation, general depreciation expense, CWIP, and (at least occasionally) AFUDC, the ALJ recognizes that adjustments to both revenues and costs can have an effect on other areas. This is particularly true with regard to the company’s overall income tax expense. The higher DTE’s projected net revenue, the higher its income tax expense, and vice versa. Thus, as with those areas, changes may need to be to the utility’s various income tax expense levels as a result of the above-described recommendations regarding revenues and expenses. As previously stated, the parties may address these potential adjustments in their exceptions and replies to exceptions, and thus provide the Commission with a more definitive estimate of the potential rate increase that may be granted to DTE in this case.

9. Other Expense

In the course of its presentation, the utility included a total of $1,585,000 in other expense. This appears to come from costs related to the amortization of loss on reacquired debt, as well as gains and losses from asset sales proposed by the company. The Staff supported use of this figure, and none of the other parties

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28 In this case, the Staff stated, in the course of its initial brief, that it agrees with the utility’s AFUDC figure of $10,806,000. See, Staff’s initial brief, p. 61. It does not appear that any of the other parties have specifically objected to that figure. Nevertheless, there remains the possibility that conclusions ultimately reached in the Commission’s final order regarding construction plans offered by the company may affect the actual level of AFUDC that should be included in this case.

29 In this area, and apparently based on DTE’s initial filing, the Staff recommended including in the utility’s overall operating expenses federal income taxes of $22,525,000, as well as state and local income taxes totaling $7,871,000 (which were increases of $14,338,000 and $2,875,000 respectively over the figures proposed by utility). See, Staff’s initial brief, p. 60.
expressed disagreement. It is therefore recommended that the Commission include the $1,585,000 figure when setting DTE’s rates in this case.

**A. Calculation of Adjusted NOI (Approximated)**

In light of the above discussion regarding both test year operating revenue and expense, the ALJ finds that DTE’s projected NOI for the test year in question should be set at $141,990,000. The computation of this figure is set forth on Attachment C to this PFD. However, because some of the numbers used by the parties in their presentations may have relied upon total company, as opposed to jurisdictional costs, that figure may have to be adjusted slightly.

**VI. OTHER COST AND REVENUE ISSUES**

Two other issues have been raised that could, depending on their treatment, effect the final gas rates approved by the Commission in this case. These consist of DTE’s request for approval of its various proposals regarding its potentially revised Revenue Decoupling Mechanism (RDM) and its Infrastructure Recovery Mechanism (IRM).

**A. DTE’s Proposed RDM Adjustment**

DTE seeks, by way of this case, to continue its existing, Commission-approved, RDM as what it refers to as a “simple revenue tracker that reconciles distribution revenue (excluding GCR revenues, surcharges, and customer charges)” with the utility’s “actual weather-normalized distribution revenue” (which, again, excludes its GCR revenues, surcharges, and customer charges). DTE’s reply brief,
p. 70. The only change that the company seeks is to remove the existing RDM revenue limit, which (having been set at 150% of the utility’s required EO targets) results in a current RDM cap that, according the utility, is only 2.25%. See, DTE’s initial brief, p. 69. According to the utility, because the average heating value of gas supplied to its customers has increased over the last 18 months, it has experienced lower average use per customer that would likely not be captured by the current RDM due to the revenue cap. See, Id., pp. 70-71. As a result, the company contends that “without (adopting the utility’s) forecasted system average heating value and proposed RDM with no revenue cap,” DTE may be “unable to fully recover its revenue losses” resulting from its EO operations which, it warns, could limit its ability “to provide the service level expected by customers.” Id., citing 2 Tr. 71.

In opposition to DTE’s request to remove the revenue cap, the Attorney General contends that, as addressed earlier in this PFD, the utility’s claim that the heating value of the gas sold to its customers will continue to increase unabated and—at least during the test year—reach a level of 1.097 Btu per Mcf is, as his witness noted, neither realistic nor supported by current data. See, Attorney General’s reply brief, pp. 17-18; See also, 3 Tr. 1007-1008.

The Staff concurs with the Attorney General and, likewise, asserts that the revenue cap that was previously imposed by the Commission “should remain in place” because it constitutes a “reasonable estimate of the maximum qualifying revenue . . . deficiency (or surplus)” that might be achieved through DTE’s EO program. Staff’s initial brief, p. 81, citing 3 Tr. 1278. Specifically, based on
testimony offered by Daniel Gottschalk, a Departmental Analyst in the Rates and
Tariffs Section of the Commission’s Regulated Energy Division, the Staff asserts
that:

The revenue caps should remain in place because they were
designed to be a reasonable estimate of the maximum qualifying
revenue (distribution revenue, excluding GCR revenues, surcharges,
and customer charges) deficiency (or surplus) that could be
experienced by the Company as a result of energy efficiency, i.e.,
assuming [that the] utility generated EO credits are a level equal to
the 150% of the statutory minimum. Gas heating values are a
traditional risk borne by the utility and should not be passed on to
ratepayers through a mechanism that, in Staff’s opinion, is intended to
remove the disincentive for the utility to promote its energy efficiency
programs.

Id.

As correctly noted by the Staff, and acknowledged by the ALJ, “caps are not
a perfect mechanism in practice.” Staff’s initial brief, p. 82. Rather, and in theory,
these caps are designed to cover all of the potential losses that could arise from
DTE’s EO program, but—in reality—these caps could capture most causes of losses
(with the exception of weather, which—by the way—is fully normalized). The
purpose of the caps in question is to set a limit on the utility’s potential loss or
increase in revenue that may arise as a result of the RDM. Moreover, and as
previously discussed in this PFD, the ALJ does not agree with DTE’s assertion that
the heating value of the gas provided to its customers will escalate to the level it
suggests, thus significantly reducing the utility’s sales levels. As a result, the ALJ
finds that the existing RDM structure, with its previously approved cap, continues to
be a reasonable compromise that serves to protect both the utility and its
ratepayers. For this reason, the ALJ recommends that the Commission reject
DTE’s request and, instead, adopt the joint recommendation of the Attorney General and the Staff to retain the existing RDM revenue limit.

**B. DTE’s Requested IRM Program**

In various orders dealing with the utility’s MMO, its Main Removal Program (MRP), and its Pipeline Integrity (PI) activities, the Commission has approved the recovery--by way of an IRM Program--of significant infrastructure investment by DTE spanning the period of 2013 through 2017.\(^{30}\) As stated by DTE in the present case, the capital expenditures used to calculate the IRM surcharge resulting from those orders are “made on a calendar year basis.” DTE’s initial brief, p. 73. Moreover, the utility continues, that particular surcharge “is calculated on a calendar year basis” for each of the five-year investment periods based upon “the cumulative cost of service associated with the incremental capital investment, and allocated to each rate schedule.” \(^{Id.}\) IRM capital spending, the utility notes, is then reconciled annually and, if required, the IRM-related surcharges are “adjusted for any underspend with the next scheduled increase in July of each year.” \(^{Id.}\) According to its witness on this issue, Don Stanczak, DTE’s Vice President of Regulatory Affairs, all capital invested as a part of the utility’s IRM is rolled into rate base, and its recovery would thus occur only after the company files--and prevails upon,

One would surmise--this issue in a general gas rate case. \(^{See, Id.}\) Finally, as specifically noted by Mr. Stanczak, the IRM-related surcharge would not expire

\(^{30}\) These Commission orders include the September 13, 2011 order in Case No. U-16407, the September 13 and November 10, 2011 orders in Case No. U-16451, the November 2015 order in Case No. U-17701, and the April 16, 2016 order in Case No. U-16999.
until the issuance of “a Commission order establishing new rates in a rate case superseding the current IRM.” 2 Tr. 77.

According to DTE, it expects that its 2015, 2016, and 2017 IRM capital expenditures would be $78.1 million, $102.1 million, and $127.6 million, respectively. See, 2 Tr. 705. Moreover, the utility expects to spend an additional $127.6 million annually on IRM-related projects from 2018 through 2021. See, Id. Also, according to testimony offered by Ms. Uzenski, and subsequently referred to by Ms. Sandberg, all of the IRM capital expenditures made (or expected to be made) through December 31, 2016 were included in the base rate figure that serves as the starting point for this case. See, Id. As noted by the company, the Commission approved a provision in its April 16, 2016 order in Case No. U-16999 to the effect that “all capital invested as part of IRM would be rolled into rate base in the event [that DTE] filed a rate case,” such as the present proceeding, including investment in its MMO, MRP, and PI programs. Id. Finally, the Commission approved additional infrastructure investments as part of an expanded IRM program covering 2016 and 2017. See, the Commission’s November 23, 2015 order in Case No. U-17701.

Consistent with the structure described above, and as stated by DTE in this case, the capital expenditures used in calculating the company’s IRM surcharge would be made on a calendar year basis for each year of the total five-year investment period “based on the cumulative cost of service associated with the incremental capital investment,” and as “allocated to each rate schedule. DTE’s initial brief, p. 73. All such spending, the utility continues, “is reconciled annually.
and, if required, the IRM surcharges are adjusted for any underspend with the next scheduled increase in July of [the] next year.” Id.

Looking ahead, DTE proposes establishing a new IRM surcharge that, it contends, is highly consistent with its currently-approved structure. The updated surcharge would take effect on January 1, 2017 to recover the cost of service associated with invested IRM capital (essentially, spending on the MRP, MMO, and PI programs) made on a calendar year basis from 2017 through 2021. See, Id., p. 74. According to the company, it “will be administratively simpler to include all invested capital through December 31, 2016 in rate base in this case, and begin the new IRM surcharge simultaneously with” the point at which the new investment in IRM (and, thus, application of the new surcharge) starts on January 1, 2017. Id., citing 2 Tr. 77-78, 503-504, 507, 679, 705, 719, 723, and 725-726.

DTE proposes that the new IRM surcharge will, as before, be calculated for each year of the total five-year investment period based on the cumulative cost of service associated with the actual MRP, MMO, and IP capital investment that occurs during each 12-month period. See, Id. Those costs would then be allocated to each rate schedule (again, in the manner discussed later in this PFD), “adjusted for any underspend,” and updated on July 1 of each year “to recover the cost of service on the incremental IRM capital investment” made during the prior calendar year. DTE’s initial brief, pp. 74-75. In addition, the utility would file a reconciliation case by the end of February of each year to reconcile the prior year’s projected

31 ABATE takes issue with this proposition, contending that the new IRM surcharge would vastly increase the amount of this spending that is assigned to large transportation customers (specifically, those taking service of rates XLT and XXLT). See, ABATE’s reply brief, p. 3. This issue will be addressed in the portion of this order concerning rate design.
spending to the IRM-related investment that actually occurred that year. See, Id., p. 75.

In addition, DTE has requested that it be allowed “an increase in spending flexibility among the [three] IRM programs,” so long as the total annual spending on IRM as a whole does not exceed the levels approved by the Commission. DTE’s initial brief, p. 75. Moreover, it takes issue with assertions made by Staff witness Creisher to the effect that the utility should, from 2012 to 2021, be “expected to impact 229,750 inside meters through the MMO, MRP, and other routine programs as outlined” in the plan proposed by the company and approved by the Commission in Case No. U-16451. See, Id., 76, citing 3 Tr. 1160. According to DTE, based upon “program design and the Company’s historical performance,” it does not believe that it is feasible to actually relocate 229,750 inside meters to the outside of their structures in the course of that 10-year period. Id. Moreover, the utility notes that, as part of the order subsequently issued in Case No. U-16999, “the scope of the MMO was modified” to simply require that the overall number of meters to be impacted by could include both inside and outside meters. Id., citing 3 Tr. 1155.

Although effectively agreeing with the overall IRM figures that DTE requests, the Staff offers four requests with regard to how those funds are both used and reported to the Commission.

First, the Staff does not believe that the utility’s request to essentially use the IRM funding however it feels fit, by providing the inter-program spending flexibility sought in this case, is reasonable. According to the Staff, if the “MMO, MRP, and PI programs” are so important that they require the additional funds” sought by the
company through base rates, “there should be no need to underspend on one program and move funds to another program.” Staff’s initial brief, p. 14.

Second, the Staff objects to DTE’s proposal to reduce (possibly to a significant level) the number of MMOs to which it previously committed. This objection is based on what appears to be the Staff’s belief that “DTE has consistently shown a lack of commitment toward the MMO program.” Id., p. 17.

Third, again based on its concern that DTE actually cares less about the entire MMO issue than it professes (at least in the course of rate case proceedings), the Staff also suggests revising the utility’s MMO reporting requirements. According to the Staff, the company should be ordered to provide a specific plan regarding the “amount of inside meters to be impacted by MRP or routine construction for the next calendar year that supports meeting the Staff’s suggested 10-year goal,” which would, as previously agreed to by DTE, necessitate addressing a total of 229,750 inside meters during that period. Id., pp. 19-20.

Fourth, the Staff concludes by recommending that DTE be required to file, on a monthly basis, “Meter Assembly Check (MAC)” progress reports that would include data consistent with that presented on page 3 of Exhibit S-7.9. Id., pp. 20-21. Although the utility contends that the semi-annual reports that it would be happy to provide should be adequate, (See, the company’s reply brief, p. 79), the Staff asserts that overdue MAC inspections are “a systemic issue directly related to the Company’s volume of meters that remain in inside locations.” Staff’s reply brief, pp. 2-3.
The Attorney General also took issue with two aspects of DTE’s proposed IRP, both of which dealt with matters relating to the MRP. First, he noted that, according to his witness, Mr. Coppola, the utility is making a grave mistake by not hiring an outside technical expert specializing in cast iron and steel pipe issues to help the company identify, and thus replace on a ranked basis, the higher priority and riskier pipeline sections first. See, 3 Tr. 1034. Second, the Attorney General asserts that no new evidence or compelling reasons have actually been presented in this case to justify an increase over the MRP-related spending level established in Case No. U-17701. See, Attorney General’s reply brief, pp. 23-24 and 27-30.

Notwithstanding this ALJ’s previously-expressed concerns regarding the adoption of IRP-like structures, at least with regard to electric utilities (see, i.e., the September 16, 2015 PFD in Case No. U-17735), it has become clear that--due to the importance of insuring the completion of MRP, MMO, and PI programs as a means of insuring public safety and system reliability for gas utilities such as DTE--the Commission believes that the use of IRPs is an acceptable mechanism for advancing investment on those worthy programs. (See, i.e., the Commission’s June 15, 2015 order in Case No. U-16999, which concerned DTE’s last gas rate case and specifically approved an IRM structure covering the utility’s MRP, MMO, and PI programs, as well as its November 23, 2015 order increasing the amount of the utility’s IRM spending). As a result, the ALJ finds that, at least in general, the IRM proposal offered by DTE in this case is reasonable and recommends that it be adopted by the Commission, albeit with a few limitations suggested by other parties.
Specifically, it appears to the ALJ that several of the concerns expressed by the Staff and the Attorney General should be resolved in their favor as part of this rate case. In this regard, the ALJ finds that the Commission should: (1) decline to approve the company’s request for what can best be described as inter-program spending flexibility within the IRM structure, for fear of leading to underspending on one or more of these important programs; (2) reject DTE’s proposal to reduce the annual number of MMO’s that it initially committed to, and concurrently adopt the Staff’s suggested MMO reporting requirements, again to assure the implementation of a vibrant MMO program; (3) require, due to evidence that overdue MAC inspections are a recurring problem [and are apparently tied to the number of meters that remain inside structures served by DTE], issuance of the progress reports recommended by the Staff in this regard; and, finally, (4) demand that, as suggested by the Attorney General, the utility hire an unbiased, outside expert regarding cast iron and steel pipe replacement issues to rank the company’s future MRP and PI projects in order of urgency.\(^{32}\)

VI.

**REVENUE DEFICIENCY CALCULATION**

In accordance with the foregoing findings and recommendations in this case, the ALJ concludes that DTE’s approximate revenue deficiency for the projected test year is $116,230,000. The calculation of that figure, and how it compares to the

\(^{32}\) Notwithstanding the four recommendations set forth above, the ALJ finds insufficient support for the second of the proposals offered by the Attorney General’s witness. Specifically, the ALJ finds that, based on the totality of the record, adequate basis exists for increasing DTE’s IRM/MRP spending beyond the levels approved in the course of Case No. U-17701.

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initial position espoused by the utility by way of its reply brief, is set forth in detail on Attachment D to this PFD.

VII.

COST OF SERVICE AND ALLOCATION OF THE REVENUE DEFICIENCY

In keeping with the respective parties’ willingness to work together and resolve as many issues between them as possible, a relatively small number of revenue deficiency allocation and rate design differences need to be addressed in this case.

Kenneth Slater, DTE’s Manager of Revenue Requirements within its Regulatory Affairs Division, provided the utility’s cost of service study (COSS) for both the 2014 historical test year, as well as a COSS covering the projected test year. See, Exhibit A-6, Schedule F6.1 and Exhibit A-13, Schedule F1.1; See also 2 Tr. 771. According to this witness, the company’s rate design in the present case is based on the Commission’s consistent and long-standing approval of a pair of demand/capacity-based cost allocation methodologies, those being, first, the Average and Peak [A&P] method for assigning functional transmission and non-customer related distribution costs, and second, a blended allocation structure for storage costs. See, 2 Tr. 775-776. In addition, DTE proposed to: (1) reduce the gas delivery loss factors applied to its high load factor transportation customers (those taking service on Rates XLT and XXLT); (2) cease assigning any distribution main and distribution operating costs—including related CWIP, accumulated depreciation, and depreciation expense—to Rate XXLT customers, and instead
assign their recovery to all non-XXLT customers,\textsuperscript{33} and (3) allocate uncollectible expenses based on net write-offs caused by each rate schedule, as was approved by the Commission in Case No. U-17689. \textit{See}, DTE’s initial brief, pp. 83-86.

The Staff offered both testimony and argument in support of most of DTE’s positions regarding the allocation of the above-mentioned costs. \textit{See}, 3 Tr. 1256-1263, and Staff’s initial brief, pp. 61-66. However, one area of dispute did arise between these two parties, namely with regard to the allocation of uncollectible expense. As opposed to the utility, the Staff recommends allocating this expense based on a customer’s total cost of service, including the cost of gas, on the grounds that—as asserted by Mr. Isakson—uncollectible expenses is “simply a cost of doing business,” and that it is “impossible to know whether uncollectibles are even correlated with net write-offs.” 3 Tr. 1252.

In contrast, ABATE adamantly contends that the Commission should reject the A&P allocation methodology and, instead rely solely on the design peak day (DPD) demand method to allocate fixed delivery system costs. \textit{See}, ABATE’s initial brief, pp. 2-3, and 5-17. According to ABATE, the A&P allocation structure (1) is “at odds with DTE’s gas distribution system design,” which is intended to meet the peak demand for all of its customers on the coldest day of the year, (2) fails to accurately reflect cost causation “because it significantly over-allocates fixed costs to large high load factor transportation customers,” and (3) conflicts with “Michigan’s

\textsuperscript{33} As specifically noted on page 84 of DTE’s initial brief, this same treatment would be provided to Dearborn Industrial Generation, LLC. No objections appear to have been made by the parties to that proposal.
stated public policy goal of making Michigan more attractive to energy-intensive industries through more competitive utility rates.” See, Id., pp. 2-3.

Turning to the next three cost allocation issues, ABATE supports DTE’s proposals to (1) “lower natural gas delivery loss factors for high load transportation customers on Rates XLT and XXLT” because it recognizes that there is a relatively lower cost to “serve customers taking high pressure natural gas delivery [i.e., big transportation customers] than low pressure classes” [i.e., commercial and residential customers], (2) to cease assigning distribution main and its related expenses—including CWIP, accumulated depreciation, and depreciation expense—to XXLT customers, and (3) to allocate uncollectable expenses by way of “the same method approved by the Commission in Cases Nos. U-17767 and U-17689, because it is a fair and accurate” means of allocating those costs. Id., p. 3.

Finally, ABATE asserts that the base rates for transportation customer classes Rate XLT and XXLT should not be increased as a result of cost assignments resulting from this gas rate case. Id. Whereas DTE and the Staff appear to seek a rate increase of 12% to 15% for these customers via various allocation measures, ABATE contends that--based on testimony its witness provided in the course of this proceeding--these classes “should receive a rate reduction of between 18% and 30%”. See, ABATE’s initial brief, pp. 3-4.34

34 In support of this argument, ABATE asserts that a comparison of large transportation customer rates between DTE and Northern Indiana Public Service Company (NIPSCO), which operates just south of the Michigan/Indiana state line, “shows that DTE has failed to establish that its requested rate relief will result in just and reasonable rates.” ABATE’s initial brief, pp. 8 and 23-24. However, as noted by several participants in this case, and fully recognized by the ALJ, there is no proper basis for setting rates in one state on the alleged rates established in another. As a result, ABATE’s assertions in this regard must be disregarded.

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Moreover, it claims that the company’s IRM surcharge increases mentioned earlier in this PFD (as well as the Staff’s higher cap on those charges as applied to XXTL customers) would unreasonably allocate up to $0.08 per Mcf to these customers’ bills. See, Id., p. 4.

With regard to the first of these cost of service/cost allocation issues, the ALJ finds that DTE’s suggested use of the A&P method to allocate transportation-related and non-customer related distribution costs, as well as its proposal to rely on the blended method for assigning storage costs, should be adopted. Both of these methods of cost allocation are in keeping with prior Commission orders, are logical, and are well supported by the record. See, 2 Tr. 775-776, as well as 3 Tr. 1256-1263.

Regarding the second and third COSS-related issues arising in this case, dealing with the utility’s proposal to reduce the loss factors for both XLT and XXLT customers, as well as to stop assigning any distribution main and related expenses to XXLT customers, none of the parties appears to take issue with those proposals. In light of that fact, and based on the supporting testimony and documentation provided in this proceeding, the ALJ recommends that both suggestions be adopted in this case.

As for the fourth issue, which deals primarily with the allocation of uncollectable expense, there is a significant difference between DTE’s proposal,

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35 In addition to its opposition for the utility’s suggested assignment of uncollectable expense to XLT and XXLT customers, and as noted above, ABATE took issue with the application of the utility’s proposed IRM charge to these customers. The ALJ does not find ABATE’s assertions persuasive on this topic, and recommends that the Commission apply the approved IRM surcharge to all customer classes, including transportation customers.
which was agreed to by ABATE (namely, assigning those costs based on net write-offs caused by each rate schedule), and the Staff’s suggestion to allocate all uncollectable expense based on total cost of service plus the cost of gas. Although the ALJ finds this to be a close call, particularly based on testimony offered by the Staff, the fact that the Commission has recently held in favor (albeit, in an electric utility case) of assigning such costs based on net write-offs, weighs in favor of adopting the position proposed by the utility and supported by ABATE. The ALJ therefore grudgingly recommends that uncollectible costs be assigned to DTE’s various rate classes based on the net write-offs for each rate schedule.

VIII.

RATE DESIGN AND OTHER TARIFF ISSUES

Based on the evidence and arguments offered by all of the parties to this general rate case (and recognizing that several erstwhile disputes have now been resolved), it appears that only four discrete issues need to be addressed with regard to rate design and other tariff-related matters. Although some require a bit more in the way of analysis and discussion, others can be addressed in a fairly brief manner.

36 For example, DTE proposed to (1) eliminate the “Low Income Senior Citizen Service Rate Schedule AS, (2) make various changes to its EUT tariffs, (3) modify the tariffs set forth in Sections E15 through E28 regarding off-system storage and transportation service, (4) make changes to its GCC program, (5) adjust the language contained in its operational flow order, (6) alter its penalties for unauthorized gas usage, (7) change Section C11.1.B pertaining to account aggregation by modifying the provision relating to what constitutes a contiguous facility, (8) make minor changes to the language found in Section C of its rate book, and (9) update the utility’s customer attachment program tariff to reflect revised percentages for DTE’s gas carrying cost rate [projected to be 11.59%] and its discount rates [proposed to be 7.98%]. See, DTE’s initial brief, pp. 87-88, and reply brief, p. 8. Because none of these proposals were opposed, and because the basis for each appears to make sense, the ALJ recommends that they be approved by the Commission.
A. Cut and Cap Charges

Among the various rate and tariff changes proposed by the utility was a request to modify the “cut and cap” charge imposed on a customer when that customer requests closing off a gas service line, generally for the purpose of demolishing a structure. DTE proposes that, notwithstanding its revision to the cut and cap structure discussed above, government-requested cut and cap operations should be exempted from the charge. See, DTE’s initial brief, p. 86. According to the company:

This modification will help facilitate blight-related demolition in an effort to reduce safety concerns, reduce theft, and support economic development in local communities for the benefit of all customers. Helping to facilitate the demolition of blighted properties supports the Commission’s recently-modified gas safety rules, as adopted in Case No. U-17462, regarding the discontinuation of inactive service lines.

DTE’s initial brief, p. 86, citing 2 Tr. 83. Previously, the Commission approved the utility’s accounting request to establish a regulatory asset for demolition-related cut and cap fees. See, the Commission’s December 22, 2015 Order in Case No. U-17991. Here, the company has “included the regulatory asset in this case, and proposes to amortize the regulatory asset over a two-year period effective with its inclusion in rate base.” Id., p. 86, citing 2 Tr. 84 and 479.

In contrast, the Staff proposed that all future cut and cap fees that are charged to non-municipal customers should continue to be included as miscellaneous revenue, and that the estimated level of those revenues (namely, $855,000) should be directly included in the computation of the projected test year revenue. See, 3 Tr. 1242. DTE agrees with the Staff that $855,000 constitutes a reasonable estimate of the utility’s test year cut and cap fees assigned to non-U-17999
municipal customers; nevertheless, the company adheres to its belief that this figure should be treated as a “credit to plant” as opposed to revenue. DTE’s reply brief, p. 83.

The ALJ disagrees with the utility on this particular issue, and recommends that the Commission adopt the Staff’s proposed treatment of this $855,000 as net revenue. Upon review of the record as a whole, the ALJ finds that the $855,000 in question should be treated as revenue received by the company.

B. IRM Changes

As addressed earlier, DTE’s revised IRM will allow it to recover its capital spending on MRP, MMO, and PI at an increasing level for the next several years, and then continuing at the year five level unless and until changed by Commission order issued in a future rate case. See, Id., p. 84. Moreover, beginning on January 1, 2017, and following on each July 1st from 2018 on, “a monthly charge will be implemented for each rate schedule as indicated on [Rate] Sheet No. D-2.01, subject to annual reconciliations.” Id. Exhibit A-18, Schedule K3 depicts these gradually increasing charges for each customer class from 2017 through 2021. For its part, the Staff supports the utility’s proposal, and suggests that the existing cap set on the recovery of IRM costs from large transportation customers should be removed entirely “to avoid [creating] subsidies between rate schedules.” Staff’s initial brief, p. 79, citing 3 Tr. 1281.

As noted previously, ABATE opposes altering the existing cap on these charges, and contends that doing so will result in large transportation customers
shouldering a much bigger share of the company’s IRM cost burden than they currently do. See, ABATE’s initial brief, pp. 4 and 20-22.

The ALJ does not find ABATE’s assertions persuasive. As noted by DTE, it is only proposing to change the maximum monthly charge assessed to its various customer classes. See, DTE’s reply brief, p. 84. As pointed out by utility witness Slater, the maximum monthly charge proposed by the company does not actually affect the allocation of IRM costs, whereas the current $500 monthly charge shifts costs to other rate schedules. See, Id., citing 2 Tr. 795 and 812. According to the company, its proposal would simply “reduce this cost shifting.” Id. This position appears to be supported by the revised direct testimony offered by Daniel Gottschalk, a Departmental Analyst in the Rates and Tariffs Section of the Commission’s Regulated Energy Division. See, 3 Tr. 1281.

Based on the evidence provided by Messrs. Slater and Gottschalk, as well as the arguments offered by DTE and the Staff, the ALJ recommends that the Commission adopt the utility’s proposal, and consider--possibly at some later time, and as suggested by the Staff--eliminating the IRM-related payment cap altogether.

C. Low Income Assistance Credit Pilot (LIACP) Rate

DTE proposes the implementation of a LIACP rate as a means of replacing the its existing Residential Income Assistance (RIA) credit, which has historically been made available to the utility’s customers taking service on Residential Service Rate A. See, DTE’s initial brief, p. 88. According to the company, the proposed pilot program:

Will provide meaningful assistance to eligible low income customers by making their bills more affordable through a $30.00 monthly bill
credit, rather than by the current $10.50 RIA monthly credit. The pilot tariff’s participation will be capped at 42,000 customers, and will require the same amount of ratepayers funding as the RIA program requires.

Id., p. 89, citing 2 Tr. 83, 799, and 828-830.

The Staff, while apparently finding potential value in the implementation of something along the lines of the company’s proposed LIACP rate, proposes that the Commission should, for the most part, keep the RIA program in place, but simply add the LIAPC to available rates (with a limit of 20,000 randomly-selected, auto-enrolled RIA customers), and set the limit of DTE’s combined RIA and LIACP customers at 100,000. See, Staff’s initial brief, pp. 70-72.

The ALJ agrees with the Staff on this issue, and recommends that the option it proposed be adopted at this time. As reflected on one of the utility’s own exhibits (Exhibit A-13, Schedule F3), DTE estimates that it has, or will have during the course of its projected test year, approximately 120,000 customers on its RIA program in any given month. By capping its new pilot program at 42,000 customers, nearly 80,000 low income customers that are currently receiving the (albeit lower) monthly credit by way of the RIA program would now be left without any assistance at all. See, 3 Tr. 1275-1276. This is a situation that the ALJ is most uncomfortable with, and which he believes the Commission cannot, in good conscience, agree to abide. As a result, the ALJ recommends that the Commission approve the LIACP suggested by the utility, but with the provisions offered by the Staff.
D. Monthly Customer Charges

In the present case, DTE proposed, among other things, to increase the monthly customer charge for residential customers taking service on Rate Schedule A to $15.00, set the same monthly charge for its Rate 2A meter class I, and increase the monthly charge for both its Rate 2A, meter class II, and Rate GS-1 to $40 per month. See, DTE’s reply brief, pp. 86-87. Moreover, based on its alleged usage of economic break-even points, the utility went on to propose raising the monthly customer charges assigned to its GS-2, Rate S [a/k/a School], Rate ST, Rate LT, Rate XLT, and Rate XXLT customers to $590, $250, $2,200, $4,200, $16,000, and $135,000, respectively. See, DTE’s initial brief, p. 96, as well as its reply brief, pp. 86-88; citing 2 Tr. 628-629, and Exhibit A-13, Schedule F2.

The Attorney General apparently asserts that the monthly charges assessed to residential customers should not be increased in this case. Even if they were raised, his witness asserted that the maximum level to be imposed on residential customers should be capped at $11.50 per month. See, 3 Tr. 1061-1062. According to the Attorney General’s witness, Mr. Coppola, if a rate increase is granted in this case, apportioning a “substantial amount to the customer charge prevents the customer from avoiding a relatively higher bill by [reducing] their usage.” 3 Tr. 1062.

As for the Staff, it asserts that monthly customer charges should be restricted to the recovery of the costs that are actually “associated with the attachment of customers to the Company’s system,” which it asserts that DTE did not do in this case. Staff’s Initial brief, p. 68, citing 3 Tr. 1250. Moreover, it
asserted that in developing its own monthly residential customer charge of $11.25, the Staff’s methodology more closely adhered to “the Commission’s guidance in [Cases Nos.] U-4771 and U-4331,” where it was clearly stated that:

Specific distribution plant such as meters and service drops used exclusively for a given customer shall be treated as customer related. See, the Commission’s May 10, 1976 order in Case No. U-4771. All other distribution plant shall be treated as demand related. [See, Attachment A, Part One of the Commission’s May 10, 1976 order in Case No. U-4471, p. 2]. The maximum allowable service charge would be limited to those costs associated directly with the supplying revenue service to a customer. Only costs associated with metering, the service lateral, and customer billing are includable since these are costs that are directly incurred as a result of a customer’s connection to the gas system. [See, the January 18, 1974 order in Case No. U-4331, p. 30].

3 Tr. 1251. Moreover, the Staff contends that although DTE claims to have calculated its customer charges based upon its COSS, the utility’s calculation, as opposed to that conducted by the Staff, “includes additional costs not directly associated with customer attachment.” Staff’s initial brief, p. 69, citing 2 Tr. 789 and 3 Tr. 1251. “Rather,” the Staff continues, “the Company includes in its proposed charge all costs classified on a capacity and customer basis, leaving the remaining commodity-classified costs” to be recovered by way of “the variable distribution charge.” Id., pp. 69-70.

The ALJ agrees with the Staff (and, essentially with the Attorney General) on this issue. Not only is it inappropriate to include any form of capacity-related costs in the computation of the fixed, monthly customer charge, but DTE’s proposal does--indeed--appear to diverge from the methodology demanded by the Commission through its orders in Cases Nos. U-4771 and U-4331. As such, the ALJ recommends that the Commission approve the Staff’s proposal regarding the U-17999
level of monthly customer charges that should be approved for use by the company. This recommendation applies to each of the above-mentioned rate classes, as well as to the meter reading surcharge discussed by the company.

IX.

CONCLUSION

Based on the foregoing discussion, the ALJ recommends that the Commission issue an order in this proceeding adopting the findings and conclusions set forth in this PFD. These include findings/conclusions to the effect that (as reflected on Attachment A) the utility’s total rate base for the projected test year should be $3,712,834,000, DTE’s overall rate of return should be set at 5.73% (as computed on Attachment B, and based on a cost of common equity of 10.00%), the company’s adjusted NOI for the test year should be set at $141,990,000 (as computed on Attachment C), and the total revenue deficiency for which DTE’s rates should be increased is $116,230,000 (as shown on Attachment D). As a result, the ALJ further recommends that the Commission authorize DTE to increase its rates for gas transportation and distribution by that amount on an annual basis.

Mark E. Cummins
Mark E. Cummins
Administrative Law Judge

October 5, 2016
### DTE Gas Company

#### Projected Rate Base

For the 13-Month Average Period Ending 10/31/2017

($000)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Source</th>
<th>(a)</th>
<th>(b)</th>
<th>(c)</th>
<th>(d)</th>
<th>(e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Plant in Service</td>
<td>Exh S-2, Sch B2</td>
<td>4,603,118</td>
<td>(22,741)</td>
<td>4,580,378</td>
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<td></td>
</tr>
<tr>
<td>2</td>
<td>Plant Held for Future Use</td>
<td>Exh S-2, Sch B2</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Construction Work in Progress</td>
<td>Exh S-2, Sch B2</td>
<td>241,807</td>
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<td></td>
</tr>
<tr>
<td>4</td>
<td>Total Utility Plant</td>
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</tr>
<tr>
<td>5</td>
<td>Accum. Depreciation Reserve</td>
<td>Exh S-2, Sch B3</td>
<td>2,166,573</td>
<td>(285)</td>
<td>2,166,289</td>
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<tr>
<td>6</td>
<td>Net Utility Plant</td>
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<td></td>
</tr>
<tr>
<td>7</td>
<td>Net Capital Lease Property</td>
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</tr>
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<td>8</td>
<td>Gas Stored Underground - non current</td>
<td>Royal</td>
<td>39,339</td>
<td>(4,072)</td>
<td>35,267</td>
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<td>9</td>
<td>Total Utility Property and Plant</td>
<td>Line 6 + Line 7 + Line 8</td>
<td>2,717,691</td>
<td>(26,527)</td>
<td>2,691,163</td>
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<td></td>
</tr>
<tr>
<td>10</td>
<td>Less: Capital Lease Obligations</td>
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<td></td>
</tr>
<tr>
<td>11</td>
<td>Net Plant</td>
<td>Line 9 + Line 10</td>
<td>2,717,691</td>
<td>(26,527)</td>
<td>2,691,163</td>
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<td>12</td>
<td>Allowance for Working Capital</td>
<td>Exh S-2, Sch B4</td>
<td>1,021,680</td>
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<td>1,021,680</td>
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<td>13</td>
<td>Total Projected Test Period Rate Bas</td>
<td>Line 11 + Line 12</td>
<td>3,739,371</td>
<td>(26,527)</td>
<td>3,712,843</td>
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</tr>
</tbody>
</table>
### Projected Rate of Return Summary

**Projected 12 Month Period Ending October 31, 2017**

($000)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Source from Exhibit A-11 Schedule</th>
<th>Amount (1)</th>
<th>13 Mo. Avg. % Amount of Permanent Capital</th>
<th>% Amount of Total Capital</th>
<th>Cost Rate %</th>
<th>Weighted Cost of Permanent Capital (%)</th>
<th>Weighted Cost of Total Capital (%)</th>
<th>Pre-tax Multiplier</th>
<th>Pre-tax Cost of Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Long-Term Debt - net (3)</td>
<td>D2</td>
<td>$1,329,379</td>
<td>48.02%</td>
<td>35.71%</td>
<td>4.98%</td>
<td>2.39%</td>
<td>1.78%</td>
<td>1.000</td>
<td>1.78%</td>
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<tr>
<td>2</td>
<td>Common Equity</td>
<td>D5</td>
<td>$1,438,768</td>
<td>51.98%</td>
<td>38.65%</td>
<td>10.00%</td>
<td>5.20%</td>
<td>3.86%</td>
<td>1.646</td>
<td>6.36%</td>
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<tr>
<td>3</td>
<td>Sub-Total</td>
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<td>$2,768,147</td>
<td>100.00%</td>
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</tr>
<tr>
<td>4</td>
<td>Short-Term Debt</td>
<td>D3</td>
<td>$137,815</td>
<td>3.70%</td>
<td>1.54%</td>
<td>0.06%</td>
<td>0.06%</td>
<td>1.000</td>
<td>0.06%</td>
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<tr>
<td>5</td>
<td>Customer Deposits</td>
<td>D3</td>
<td>8,918</td>
<td>0.24%</td>
<td>7.00%</td>
<td>0.02%</td>
<td>0.02%</td>
<td>1.000</td>
<td>0.02%</td>
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<tr>
<td>6</td>
<td>Other Interest Bearing Credits</td>
<td>D3</td>
<td>3,869</td>
<td>0.10%</td>
<td>1.84%</td>
<td>0.00%</td>
<td>1.000</td>
<td>0.00%</td>
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<tr>
<td>7</td>
<td>Net Deferred Federal Income Tax (2)</td>
<td></td>
<td>800,814</td>
<td>21.51%</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<tr>
<td>8</td>
<td>Deferred Investment Tax Cr.</td>
<td></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
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</tr>
<tr>
<td>9</td>
<td>JDITC - Long-Term Debt</td>
<td></td>
<td>1,495</td>
<td>0.04%</td>
<td>4.98%</td>
<td>0.00%</td>
<td>1.000</td>
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<tr>
<td>10</td>
<td>JDITC - Common Equity</td>
<td></td>
<td>1,618</td>
<td>0.04%</td>
<td>10.00%</td>
<td>0.00%</td>
<td>1.646</td>
<td>0.01%</td>
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<tr>
<td>11</td>
<td>Total JDITC</td>
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<td>3,113</td>
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<td></td>
</tr>
<tr>
<td>12</td>
<td>Total</td>
<td></td>
<td>$3,722,676</td>
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<td></td>
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</tr>
</tbody>
</table>

(1) Source: Exhibit A-9, Schedule B5
(2) Exhibit A-9, Schedule B5, Lines 71, 72, 73 less Lines 41 and 42
(3) Outstanding long-term debt less unamortized discount balance (Line 49) net of unamortized debt expense (Line 32)
### Michigan Public Service Commission
### DTE Gas Company
### Adjusted Net Operating Income
### Projected 12 Month Period Ending October 31, 2017
### ($000)

#### Company (Reply Brief)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description (Witness)</th>
<th>Distribution</th>
<th>Transportation &amp; Storage</th>
<th>Other</th>
<th>Total</th>
<th>Cost of Gas Sold</th>
<th>Company Use and Lost Gas</th>
<th>Gas Uncollectibles</th>
<th>Deprec. &amp; Amort.</th>
<th>Property &amp; State &amp; Local IT</th>
<th>FIT</th>
<th>Other</th>
<th>Total</th>
<th>NOI</th>
<th>AFUDC</th>
<th>NOI</th>
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<tr>
<td>1</td>
<td>Operating Income</td>
<td>607,610</td>
<td>74,421</td>
<td>92,533</td>
<td>774,563</td>
<td>-</td>
<td>34,020</td>
<td>381,837</td>
<td>4,996</td>
<td>10,187</td>
<td>1,585</td>
<td>668,703</td>
<td>116,666</td>
<td>105,860</td>
<td>10,806</td>
<td>116,666</td>
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<tr>
<td>2</td>
<td>Gas Sales</td>
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<td>-</td>
<td>16,620</td>
<td>-</td>
<td>1,090</td>
<td>5,436</td>
<td>6,526</td>
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<tr>
<td>3</td>
<td>End-User Transportation</td>
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<td>-</td>
<td>1,836</td>
<td>-</td>
<td>120</td>
<td>601</td>
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<tr>
<td>4</td>
<td>Misc Revenue</td>
<td>855</td>
<td>855</td>
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<td>-</td>
<td>56</td>
<td>290</td>
<td>336</td>
<td>-</td>
<td>519</td>
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<tr>
<td>5</td>
<td>Gas in Kind</td>
<td>6</td>
<td>6</td>
<td>-</td>
<td>-</td>
<td>0</td>
<td>2</td>
<td>2</td>
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<td>6</td>
<td>Grantor Trust Income</td>
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<td>77</td>
<td>385</td>
<td>462</td>
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<td>Company Use &amp; Lost Gas</td>
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<td>(667)</td>
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<tr>
<td>10</td>
<td>Incentive Compensation</td>
<td></td>
<td>(11,152)</td>
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<td>731</td>
<td>3,647</td>
<td>(6,773)</td>
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<td>6,773</td>
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</tr>
<tr>
<td>13</td>
<td>SERP</td>
<td></td>
<td>(644)</td>
<td>-</td>
<td>-</td>
<td>42</td>
<td>211</td>
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<td>626,066</td>
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### Projected Revenue Deficiency (Sufficiency)
**Projected 12 Month Period Ending October 31, 2017**
($000)

<table>
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<th>Line</th>
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<th>Source</th>
<th>Applicant Projection (Reply Brief)</th>
<th>ALJ Adjustments</th>
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<td>1</td>
<td>Rate Base</td>
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<td>$3,739,371</td>
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<td>3</td>
<td>Overall Rate of Return</td>
<td>Line 2 ÷ Line 1</td>
<td>3.12%</td>
<td>0.70%</td>
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<td>Projected Rate of Return</td>
<td>Appendix D</td>
<td>6.02%</td>
<td>-0.29%</td>
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<td>5</td>
<td>Income Required</td>
<td>Line 1 x Line 4</td>
<td>$224,929</td>
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<td>Income Deficiency / (Sufficiency)</td>
<td>Line 5 - Line 2</td>
<td>$108,264</td>
<td>$(37,667)</td>
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<td>Revenue Deficiency / (Sufficiency)</td>
<td>Line 6 x Line 7</td>
<td>$178,245</td>
<td>$(62,015)</td>
<td>$116,230</td>
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