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July 17, 2015

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: Case No. U-17735 - In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief

Dear Ms. Kunkle:

Enclosed for filing please find the **"Initial Brief of Consumers Energy Company."** This is a paperless filing and is therefore being filed only in a PDF format. I have enclosed a Proof of Service showing electronic service upon the parties.

Sincerely,

Bret Totoraitis
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cc: Hon. Mark E. Cummins, Administrative Law Judge
Parties per Attachment 1 to Proof of Service

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief	))))))	Case No. U-17735

INITIAL BRIEF OF CONSUMERS ENERGY COMPANY

July 17, 2015

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STATE OF MICHIGAN

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INITIAL BRIEF OF CONSUMERS ENERGY COMPANY

I. INTRODUCTION AND OVERVIEW

A. Procedural Overview

On December 5, 2014, Consumers Energy Company ("Consumers Energy" or "the Company") filed its Application in this case, seeking a three-stage adjustment in its electric rates sufficient to produce net additional revenues in the approximate annual amount of $163 million. This amount was calculated based, in part, on the Company's then-approved electric depreciation rates set in Case No. U-16054. However, the Company proposed in its Application to further adjust the final rate relief requested in this case to account for the depreciation rates established in then-pending Case No. U-17653 if a final order in that proceeding was issued before the final order in this case. That contingency has occurred. See, MPSC Case No. U-17653, Order Approving Settlement Agreement (dated May 14, 2015). The new depreciation rates result in approximately $33.5 million additional depreciation expense in this case. 5 TR 340. As a result of this and other developments consistent with the Company's December 5 Application, the Company's request for the net final rate relief in this case has subsequently been increased to $198.6 million. See Appendix A, line 11, column (d).

Pursuant to MCL 460.6a(1), absent an order from the Michigan Public Service Commission ("MPSC" or the "Commission") that either prevents or delays self-implementation, Consumers Energy was authorized to self-implement up to the full amount of its proposed rate increase on June 4, 2015. In accordance with the schedule established by Administrative Law Judge ("ALJ") Mark E. Cummins in the case, Consumers Energy filed the testimony and exhibits of one witness on May 14, 2015 indicating the Company's intent to self-implement a $110 million increase. The Commission Staff ("Staff") also filed testimony regarding self-implementation. At the self-implementation hearing held on May 18, 2015, Staff's and the Company's respective testimonies were bound into the record without the need for cross-examination. Consumers Energy and Staff filed self-implementation briefs on May 21, 2015. No party filed a reply brief. Thereafter, the Commission did not issue an order preventing or delaying self-implementation. Accordingly, the Company's $110 million self-implemented increase went into effect on June 4, 2015.

Evidentiary hearings in this case then commenced June 10, 2015, and were concluded June 17, 2015. Pursuant to the schedule established by the ALJ, Initial Briefs are due July 17, 2015, and Reply Briefs are due August 7, 2015. A Proposal for Decision ("PFD") target date is set for September 21, 2015.

B. Executive Summary/Overview of Company Requests

Garrick J. Rochow provides an overview of the Company's request in this case. 5 TR 142-170.[1] The $193.5 million of net annual rate relief requested by the Company is primarily driven by the Company's continued investment in Michigan, including the Company's purchase of an existing 540 megawatt combined cycle natural gas-fueled electric generating plant located

[1] At the June 10, 2015 evidentiary hearing in this case, Mr. Rochow adopted and sponsored the testimony and exhibit originally pre-filed by Company witness Patricia K. Poppe in this case. 5 TR 137-138.

in Jackson, Michigan ("the Jackson Gas Plant"). 5 TR 152, 153. Approximately $211 million, or 130%, of the Company's original request is comprised of investment related costs. 5 TR 152. Mr. Rochow identified four main categories of investments that the Company has made, and continues to make, to improve the value of the services the Company provides to its customers since rates were established in the Company's last rate case. These include investments to ensure generation supply reliability, distribution system reliability, protection of the environment, and enhanced technology. 5 TR 153-157.

Mr. Rochow testified that the Company's investment decisions are driven by Consumers Energy's goal of improving customer value, customers' satisfaction with their utility service, and all aspects of the customer experience. 5 TR 146-151. Consumers Energy is highly engaged in listening and responding to its customers' preferences and concerns, both through the informal contacts that the Company makes with its customers on a day-by-day basis, and also through more formal and deliberate methods such as focus groups and quantitative survey research. 5 TR 147. Mr. Rochow testified that the primary external benchmark of customer satisfaction used by the Company is J.D. Power survey data. 5 TR 147. He testified that Consumers Energy uses the J.D. Power survey results as a guide for improvement. 5 TR 149. "We rank the areas that are most important to customers and work to improve our performance in these areas." 5 TR 149. Mr. Rochow further testified:

> "With the rich data set that our customers provide through J.D. Power surveys, there is no longer the need to speculate about what truly drives their satisfaction. We have the data driven and analytical basis for making investment decisions and process improvements that will have the greatest impact on our customers' satisfaction. Thus, Company decisions on where to invest its resources are driven by what provides the greatest value to our customers, based not upon our opinions or hypotheses, but rather through direct customer feedback." 5 TR 149.

As a result, the survey data has shown that this customer-focused investment planning has worked exactly as intended to increase the customers' sense of value regarding the service that Consumers Energy provides to them. The Company has increased its overall Customer Satisfaction Index score in its J.D. Power surveys from 631 in 2013 to 650 in 2014 and 663 in 2015. 5 TR 149. The Company was recognized as the second-most trusted combination utility brand in the Midwest among residential customers and continues to improve its performance among residential customers on the survey year after year. 5 TR 149-150.

The Company's original filing in this case also includes an increase in total Operating and Maintenance ("O&M") expense of $26 million when compared to current rate levels. 5 TR 157. That level of O&M expense increase represents about a 2% increase per year in O&M costs since rates were last reset in Case No. U-17087. 5 TR 158. Mr. Rochow testified that Consumers Energy works diligently to manage expenses so that customers are not asked to pay for things which are not value-adding and that one of the Company's focuses for capital investments is to spend in areas that reduce O&M expense. 5 TR 159. Mr. Rochow described a number of examples of the efforts Consumers Energy has made to minimize O&M expense increases. Among other examples, those efforts include: (1) investments in the Company's High Voltage Distribution ("HVD") and Low Voltage Distribution ("LVD") systems that reduce operating expense as well as increasing the reliability and effectiveness of the Company's power plants; (2) improvements in generation reliability, which reduced fuel expenses by more than $3.6 million per year; (3) improvements in employee safety, which impacts costs by reducing employee medical claims and lost work days (saving approximately $2 million annually); (4) implementing voluntary workforce reduction programs in 2012 and 2013 and other actions which led to best-in-class improvements in the Company's productivity performance; and

(5) using cost-per-outage-minute estimates from Berkeley Labs, which resulted in a seven-minute reduction in average outage minutes from 2006 and resulted in annual savings to business customers of more than $25 million. 5 TR 159-160.

Mr. Rochow also testified that the Company was able to avoid other potential cost increases in this case (1) by obtaining Commission authorization to modify accounting practices that impact how the Company's income tax benefits related to the cost of removal of certain properties are recognized (saving customers $42 million annually) and (2) as a result of the impending elimination of the Rate E-1 subsidy and modest sales forecast increases (reducing the Company's revenue requirement by $30 million). 5 TR 162-163.

Finally, Mr. Rochow described several significant developments coming between the filing of this case and the end of the Company's proposed test year, which require a three-stage approach to implementing the rate increase that the Company requests. First, Mr. Rochow testified that the Company's purchase of the Jackson Gas Plant is expected to close shortly after the Commission issues its final order in this case. 5 TR 164. However, the Company expects there to be a short period of time in which the new rates from this case will be in effect before the Company owns and operates the Jackson Gas Plant. Therefore, the Company proposes that the first stage of rate adjustments in this case should be a rate increase that includes all of the Company's proposed cost increases, including those associated with the Jackson Gas Plant, but which also includes negative surcharges that will have the effect of temporarily removing the Jackson Gas Plant costs from rates. 5 TR 164. The Company proposes that the second stage of rate adjustments in this case should be the termination of the negative surcharges offsetting the Jackson Gas Plant costs, which should occur on the actual closing date of the Jackson Gas Plant purchase. 5 TR 165. The Company proposes that the third stage of rate adjustments in this case

should be a rate decrease in an annual amount of approximately $38 million dollars, which should occur when the Company completes its planned retirement of seven coal generating units and removes the associated O&M for those units from rates. 5 TR 165.

The Staff's position in this case indicates an initial revenue deficiency of approximately $25.8 million. It should be noted that Staff's testimony was filed before the Commission's Order approving the settlement in Case No. U-17653 and does not include the impact of the increased depreciation expense resulting from the new depreciation rates authorized by the Commission in that case. Appendices A-E attached to this Brief show, in summary form, the Company's initial position, the Staff's as–filed position, the Company's Brief position, and the variance between the Company's and Staff's positions.

The Company disagrees with many of the proposals included in the testimony filed by Staff and the intervenors in this case. The Company in this Brief addresses several anticipated areas of dispute and relies upon the record and evidence in support of its requested rate relief. As discussed below, the record evidence in this case supports final rate relief in the annual amount of $193.6 million, including a 10.7% return on equity, approval of the purchase of the Jackson Gas Plant, authorization to implement an Investment Recovery Mechanism ("IRM") for reconciliation in calendar years 2017 and 2018, approval of the Company's proposed Revenue Adjustment Mechanism conditioned on enactment of appropriate authorizing legislation, and approval of all of the other various requests included in the Company's filings. All other parties' arguments to the contrary should be rejected, and the Commission should issue an order granting the Company's requested relief in full.

II. TEST YEAR

In each rate case, a test year must be selected. In this regard, it should be noted 2008 Public Act 286 ("PA 286") specifically provides for the use of "projected" test years in setting utility rates. MCL 460.6a(1). Consumers Energy used a projected 12-month test year ending May 31, 2016 for determining final rate relief. 5 TR 312. In developing projected test year data, Consumers Energy began with a 2013 historical period, which was then adjusted to reflect updated sales and projections of investments, expenses, and revenues. 5 TR 310-312.

III. RATE BASE

A. Net Utility Plant

1. Distribution Capital and Energy Supply Capital Expenditures (Non-Advanced Meter Infrastructure ("AMI")

a. Company's Position

Company witness Mary P. Palkovich, Vice President of Energy Delivery, testified concerning the Company's electric distribution capital expenditures. Ms. Palkovich's testimony described in detail the capital expenditures proposed for inclusion in the Company's rate base for the projected test year, as well as the analytical rationale for these expenditures. 8 TR 1330-1341, Exhibit A-52 (MPP-2). As shown in Exhibit A-52 (MPP-2), the Company is requesting rate recovery of its electric distribution capital expenditures for the years 2013; 2014; 2015; the five months ending May 31, 2016; the seven months ending December 31, 2016; and the years 2017 and 2018 in the amounts of $363,383,000; $374,379,000; $446,016,000; $189,808,000; $280,727,000; $533,857,000; and $535,652,000. 8 TR 1330. These expenditures are based on the investment levels necessary to account for new business, to address customer reliability expectations, to meet expected load, to replace assets in response to emergent demand

failures, to relocate electric distribution infrastructure, and for fleet/facility upgrades. 8 TR 1331.

The electric distribution capital expenditures are divided among seven major expense categories or programs. 8 TR 1331. As shown on Exhibit A-52 (MPP-2), the major programs are: (1) New Business; (2) Reliability; (3) Capacity; (4) Demand Failures; (5) Asset Relocations; (6) Technology/Production Support; and (7) Electric Business Services. 8 TR 1331. Each of these programs is explained and supported in detail in Ms. Palkovich's testimony. 8 TR 1331-1341. These distribution capital expenditures, in conjunction with the O&M expenses, address the three leading causes of customer outages on the Company's electric system: tree related, equipment failures, and lightning/weather. 8 TR 1334. The Company's projected level of capital expenditures will help improve system reliability and enhance customer satisfaction through a reduction of customer outages. 8 TR 1334.

b. <u>Areas of Dispute with Staff</u>

Consumers Energy requests that the Commission reject Staff's proposed expenditure reduction to the Demand Failure, Capacity, and New Business Programs. Staff's proposed adjustments lower the Demand Failure program category to a test year projection of $103,278,000, the Capacity program category to a test year projection of $52,516,000, and New Business program category to a test year projection of $55,500,000.[2] 9 TR 1908. The Staff's proposed expenditure levels fail to accurately account for the Company's investments in the Demand Failure, Capacity, and New Business Programs, which are necessary programs to provide reliable service to the Company's customers. Therefore, the Company's projected capital expenditures are appropriate, reasonable, and prudent.

[2] During cross-examination, Staff revised the numbers contained in their pre-filed testimony. This revision utilized the proper 2012 actual number to calculate the Staff's proposed expenditure level based on the use of a five-year average. 9 TR 1909-1910.

The Staff's first proposal is to adjust the Company's projected demand failure expenditures. These expenditures are incurred in connection with customer outage restoration and the repair, or replacement, of equipment due to unanticipated or imminent failure. 8 TR 1338. The Demand Failure Program directly impacts customers as these expenditures are directly related to a customer's service – either for service restoration or the installation of new equipment that will improve service. 8 TR 1338-1339. Staff proposes to use a five-year average to project the Company's demand failure expenditures. 9 TR 1908-1909. This expenditure level fails to account for the recent investments incorporated in the demand failure category.

The Company's demand failure expenditures include the Mercury Vapor Streetlight Conversion, which started in 2011, and a projection to enhance the credit available for customers who request conversion of existing street lighting to Light Emitting Diode ("LED") fixtures. 8 TR 1339. These investments have not previously been included in historical expenditure levels. 8 TR 1357-1358. Staff's historical five-year average fails to fully take into account the Mercury Vapor Streetlight Replacement Program, which has had an average annual expenditure amount of $3,256,000, and ignores the Company's projection of the additional LED lighting credits in the amount of $4,250,000. 8 TR 1357, 1358. Additionally, the use of a five-year average fails to recognize the capitalization of pole-top hardware, which will increase the demand failure expenditures in the amount of $31,520,000 annually. 8 TR 1357. The Staff's methodology does not incorporate the expansion of the demand failure category. The Company's projections are a more accurate and reasonable representation of the necessary investments needed to respond to customer interruptions and imminent failures and should be used in setting rates.

Staff's second proposed adjustment is to the Company's capacity expenditures. Similar to the Demand Failure Program, the Company's projected expenditures for the Capacity Program are a reasonable representation of Consumers Energy's spending to ensure that the electric system is capable of serving forecasted electric peak demand. 8 TR 1359. Consumers Energy undertakes capacity projects to ensure that the system has enough capacity to service customers during periods of peak load. 8 TR 1358. Company witness Palkovich testified that capital investments in the capacity category are necessary to:

> "1) ensure that the HVD electric system is capable of serving forecasted electric peak demand with all HVD facilities in-service; 2) ensure that single facilities of the HVD system can be taken out of service during non-peak demand periods for maintenance and construction without loading remaining HVD facilities above emergency ratings or serving customers with unacceptable low voltage; and 3) fix LVD system overloads and low voltage occurrences after they occur." 8 TR 1338.

Staff witness Ryan Laruwe proposed reducing the Capacity Program to a test year projection of $52,516,000, which is based on a historical five-year average. 9 TR 1910. In support of the Staff's proposed reduction, Mr. Laruwe indicated that capacity spending should not increase at a time of declining system peak capacity. 9 TR 1910. This line of reasoning reflects a misunderstanding of how capacity expenditures are incurred. The Capacity Program expenditures are not related to the system as a whole. These expenditures are based upon localized growth, which drives the need for different capacity projects across the Company's service territory. 8 TR 1359.

Staff's use of a historical five-year average to calculate the expenditures for the Capacity Program does not accurately reflect the Company's capacity spending. A review of Exhibit A-113 (MPP-8) shows that the Company has historically spent more than the projected level of expenditures. 9 TR 1358. As Ms. Palkovich testified, "the Company's eight-year average spend

for the Capacity Program is $61,401,000." 9 TR 1358. Moreover, the use of a historical average fails to incorporate new capacity projects, like the rebuilding of the Ellsworth substation in Grand Rapids, which the Company is undertaking. 8 TR 1359. The Staff's proposed use of historical five-year average understates the necessary expenditures for the Capacity Program. Consumers Energy requests that its projected Capacity Program expenditures be adopted by the Commission as a reasonable and prudent investment by the Company to meet its obligation of ensuring the electric system is capable of serving forecasted electric peak demand.

The Staff's third proposed adjustment in this area of expenditures is to the New Business Program category. These expenditures consist of the cost of adding new commercial, industrial, and residential customers. Included in the New Business Program expenditures are the cost of installing poles, conductors, transformers and services, the cost of meters to service new customers, and the cost of installing new customer requested streetlights. 8 TR 1331. When evaluating the expenditure level for the New Business Program, Staff witness Laruwe stated that "Consumers has not provided conclusive evidence that they do not currently have the capacity to serve this increased level of new customers…." 9 TR 1912. This represents a misunderstanding of the New Business Program as these expenditures are not related to capacity. The Company is bound by its tariffs and must provide service to customers in its service territory regardless of whether or not the system has capacity to serve these customers. 8 TR 1360.

Staff recommended reducing the Company's projected new business expenditure amount to $55,500,000, which is based on a two-year average of capital spending. 9 TR 1912. Staff questioned the Company's projected new business expenditure level based on the belief that it showed a 24% increase in customer growth. 9 TR 1911-1912. However, the Company's projection is only partially based on customer growth. Company witness Palkovich testified that

the New Business Program has experienced an increase in costs due to primary line extensions, longer services, and increased installations of LED streetlights. 8 TR 1359. Thus, the Commission should reject Staff's proposed disallowance as a two-year average does not adequately reflect New Business Program's projected customer growth and cost increases that the Company is experiencing.

c. Areas of Dispute with the Attorney General

Consumers Energy requests that the Commission reject the Attorney General's proposed reduction to the Company's electric distribution capital expenditures. The Attorney General argued that the capital expenditure amount for 2015 and 2016 should be based on a normalized historical level of $125 million, which includes the Company's proposed pole-top capitalization. 10 TR 2309. This results in a reduction of $20.6 million from the Company's projected expenditure level. 10 TR 2309.

The Attorney General alleged that his proposed new business expenditure amount was reasonable because the Company's projection was unsupported. 10 TR 2306. This assessment is inaccurate. The Attorney General inappropriately disregarded information provided by the Company. For each category of proposed reductions, the Company provided testimony detailing each expenditure category and explaining the reasonableness of the Company's projections. 8 TR 1331-1341, 1356-1361, 1369-1371. Additionally, the Company responded to numerous discovery requests regarding the cost increases associated with the New Business Program. Exhibit A-114 (MMP-9). These responses demonstrate a trend of more costly primary line extensions and additional installations of LED streetlights. 8 TR 1369. The Attorney General failed to take into account these increased costs.

The Attorney General next proposed to lower the Company's projected Reliability Program expenditure amount. 10 TR 2306-2307. Attorney General witness Coppola claimed

that the Company's Reliability Program projection is not justified by the number of pole replacements and work orders the Company projects. 10 TR 2307. This assertion inappropriately ignores Ms. Palkovich's testimony explaining that the Company has included the expansion over historical years of the number of circuits it will perform pole-top rehabilitation on, which will overall improve system reliability and reduce customer outages. 8 TR 1333. Exhibit AG-11 depicts the increase in the number of work orders for pole-top circuit rehabilitation, which the Company projects to grow from 100 in 2015 to 550 in the first five months of 2016. 8 TR 1370. The Attorney General's proposed Reliability Program expenditure amount does not accurately provide for the Company's investments to ensure improved customer reliability and should be rejected.

The Attorney General also proposed reducing the Company's projected expenditures for the Capacity Program. 10 TR 2307-2308. In making his proposed disallowance, Mr. Coppola attempts to draw a comparison between the Capacity Program and the New Business Program. 10 TR 2307-2308. These programs are unrelated. Capacity projects ensure that the system has enough capacity to service customers during periods of peak load. 8 TR 1358. These projects are designed to:

> "1) ensure that the HVD electric system is capable of serving forecasted electric peak demand with all HVD facilities in-service; 2) ensure that single facilities of the HVD system can be taken out of service during non-peak demand periods for maintenance and construction without loading remaining HVD facilities above emergency ratings or serving customers with unacceptable low voltage; and 3) fix LVD system overloads and low voltage occurrences after they occur." 8 TR 1338 and 8 TR 1371.

In contrast, new business projects are the cost associated with providing service to new customers, which include the installation of poles, conductors, transformers and services, the cost of meters to service new customers, and the cost of installing requested streetlights. 8 TR 1331.

The Capacity Program expenditures benefit all customers as these investments ensure that customers do not experience voltage problems and that they have continuous, reliable service. 8 TR 1371. The Company's projected Capacity Program expenditures are reasonable and prudent investments to ensure the system is capable of serving forecasted peak demand and should be approved by the Commission.

Lastly, the Attorney General proposed to reduce the Company's projected demand failure expenditures. Mr. Coppola argued that the Company's projection should be disregarded because the only known change going forward is the capitalization of additional costs for pole-top hardware beginning in 2015. 10 TR 2309. While recognizing the capitalization of pole-tops, Mr. Coppola ignores that this results in an increase in expenditures in the amount of $31,520,000 annually. 8 TR 1357. Additionally, as explained previously, the Demand Failure Program expenditures include investments not previously included in historical expenditure levels such as the Mercury Vapor Streetlight Replacement and the projection of additional LED lighting credits. 8 TR 1357-1358. The Attorney General's proposal does not fully recognize the investments made in the Demand Failure Program and should be rejected.

2. Fossil and Hydro Generation Capital Expenditures Company's Position

a. Acquisition of the Jackson Gas Plant

The Company's plan to acquire the Jackson Gas Plant is being implemented to address the need for additional capacity. Changes in environmental requirements, primarily the Mercury and Air Toxics Standards ("MATS")[3] rules administered by the United States Environmental

[3] On June 29, 2015 the United States Supreme Court issued its opinion in *Michigan v Environmental Protection Agency*, 576 US __; __ S Ct __; __ L Ed 2d __ (2015) (slip op), holding that the EPA did not conform with the statutory requirements of the Clean Air Act in promulgating the MATS Rules. The Company is still evaluating the impact of that decision. The Company does not currently expect the Supreme Court's decision to affect the Company's plans with respect to any issue included in this case. It should be noted that Consumers Energy remains subject to the Michigan Mercury Rule affective January 1, 2015. 7 TR 1233.

Protection Agency ("EPA") caused the Company to plan the retirement of certain electric generating units and created the need for the Company to acquire additional capacity. 8 TR 1499. Two of the Company's coal-fueled generating units will be modified to comply with the MATS rule by April 15, 2015. *Id.* The other ten of the Company's coal-fueled generating units must comply with the MATS rule by April 16, 2016. The Company plans to modify three of those ten generating units to ensure MATS compliance and to retire the remaining seven coal-fueled electric generating units. 8 TR 1499-1500. Company witness Davis F. Ronk, Jr., the Company's Executive Director of Transactions and Wholesale Settlements, explained:

> "The Company has concluded that it would not be cost-effective to modify and operate seven of its twelve coal-fueled generating units beginning April 16, 2016.[4] On March 14, 2013, the Company advised Midcontinent Independent System Operator, Inc. ('MISO')[5] that it intends to suspend operation of those generating units from April 15, 2016 to April 15, 2019. On June 5, 2013, MISO advised that the Company's plan to remove the seven coal-fueled generating units from service would not create reliability issues associated with operating the transmission system. On September 17, 2014, the Company advised MISO that it plans to retire the seven coal-fueled generating units effective April 15, 2016. In MPSC Case No. U-17473, the Company also applied for securitization of the remaining book value of these seven coal-fueled generating units. The Commission approved the sale of securitization bonds in its December 6, 2013 Order in that case. Suspension of operations of these seven generating units will remove approximately 956 megawatts ('MW') of nameplate capacity from the Company's portfolio. For MISO Planning Year 2016 (the 12 months beginning June 1, 2016) the Company expects to need approximately 890 Zonal Resource Credits ('ZRC') to replace the ZRCs associated with the 956 MW of capacity that will be removed from service. Thus, the Company has investigated the acquisition of additional generating resources." 8 TR 1500.

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[4] The seven generating units are Cobb Units 4 and 5, Weadock Units 7 and 8, and Whiting Units 1, 2, and 3. The generating units are sometimes referred to as the "Classic Seven." 8 TR 1500.

[5] Previously Midwest Independent Transmission System Operator, Inc. 8 TR 1500.

The Company has conducted a number of capacity solicitations and analyses since 2012. 8 TR 1501. Mr. Ronk explained:

> "On June 1, 2012, the Company solicited proposals for the purchase of approximately 1,000 ZRCs for planning years 2015, 2016, and 2017, and extended an invitation for owners of existing natural gas-fueled generation units to submit proposals for the Company to purchase those assets;
>
> "In 2012, the Company conducted a comprehensive siting study for a possible new plant to be constructed and the Company filed for an air permit (permit to install) for two combined cycle units at the Thetford site from the MDEQ;
>
> "In June 2013, the Company filed an application for approval of a Certificate of Necessity for the Thetford Generating Plant, a nominal 700 MW natural gas-fueled combined cycle electric generating facility, and for related accounting and ratemaking authorizations (MPSC Case No. U-17429);
>
> "On September 30, 2013, the Company issued a Request for Proposals ('RFP') seeking proposals to sell existing natural gas-fueled generating facilities located in MISO Zone 7 to Consumers Energy;
>
> "The Company evaluated responses to its September 30, 2013 RFP and concluded that it would acquire the Jackson Plant; and
>
> "On January 30, 2014, the Company's signed agreement to purchase the Jackson Plant, an existing 540 MW combined cycle natural gas-fueled electric generating plant, located in Jackson, Michigan was announced and the Company withdrew its Certificate of Necessity application for the Thetford Plant (MPSC Case No. U-17429)." 8 TR 1501.

The Company received proposals to sell five existing generating plants in 2012, but determined that none of the proposals was significantly better than construction of the new Thetford Plant to meet the capacity shortfall. 8 TR 1501-1502. Due to a perceived softening in the capacity market during the pendency of Case No. U-17429 (the Thetford Certificate of Necessity proceeding), the Company issued another Request for Proposal ("RFP") on

September 30, 2013, seeking proposals to sell existing natural gas-fueled generating facilities located in Midcontinent Independent System Operator, Inc. ("MISO") Zone 7 to the Company. 8 TR 1502. The Jackson Gas Plant was one of the options provided through the September 2013 RFP process. The Company determined that the purchase of the Jackson Gas Plant, to address capacity shortfalls in years 2016 and beyond, for $155 million was reasonable and prudent and would save customers money compared to building the Thetford Plant for $700 million. *Id.* The purchase cost per kW of capacity for each resource option considered in the September 2013 RFP is set forth on Exhibit A-60 (DFR-3). The Company's ability to purchase the Jackson Gas Plant by 2016 when capacity and energy of the plant is necessary to meet customer demand and not sooner saves the Company's customers the costs associated with an earlier plant purchase when the capacity and energy is less necessary to meet customer demand, as would have occurred if a plant had been purchased pursuant to the 2012 RFP. The Company's plan to purchase the Jackson Gas Plant is reasonable and prudent and helps ensure the delivery of reliable and cost-effective capacity and energy for customers.

b. Generation Capital Expenditures including the Jackson Gas Plant

Company witness David B. Kehoe, Director of Staff Electric Generation, testified concerning Consumers Energy's Fossil and Hydro Generation Capital Expenditures. At 6 TR 698-714 and Exhibit A-47 (DBK-4), Mr. Kehoe described the capital expenditures proposed for inclusion in the Company's rate base for the projected test year as well as the analytical rationale for these expenditures. Mr. Kehoe testified in support of Company capital expenditures for Fossil and Hydro Operations in the amount of $425.3 million for 2013, $462.9 million in 2014, $524.2 million in 2015, $266.4 million in 2016, $205.5 million in 2017, and $310.9 million in 2018. 6 TR 699.

Mr. Kehoe testified that compliance with the Clean Air Act ("CAA") and maintaining plant reliability are the major drivers of capital expenditures for the generating plants. 6 TR 698. Mr. Kehoe provided a detailed explanation of both categories of capital expenditures at 6 TR 701-714. In summary, a large percentage of the capital expenditures will result in cleaner air and are needed to remain in compliance with state and federal environmental requirements. 6 TR 698-699. Another significant portion of the described capital expenditures will improve reliability which will shield customers from the high-priced spot market, improve unit efficiency, and reduce fuel costs. *Id.*

Included in the above projected capital expenditures are amounts related to the Company's Jackson Gas Plant. 6 TR 707. Page 1, line 7 of Exhibit A-47 (DBK-4) identifies the total projected capital expenditures for this plant. Specifically, the Company projects capital expenditures in the amount of $200,000 for 2014, $155 million in 2015, $9.6 million in 2016, $9.6 million in 2017, and $10.7 million in 2018. Exhibit A-47 (DBK-4). The 2014 and 2015 expenses will be incurred by the Company for the purpose of monitoring operations at the plant and for the Company's projected December 2015 purchase. 6 TR 707. The Company will incur capital expenditures at the Jackson Gas Plant in 2016 through 2018 related to a long-term service agreement ("LTSA") with General Electric ("GE").

In addition to providing the Company's projected capital expenditures at the Jackson Gas Plant, Mr. Kehoe also discussed the design of the plant and the future benefits that will be provided to customers. 6 TR 707-709. Mr. Kehoe explained that the Jackson Gas Plant is an existing facility with a proven record of being efficient, flexible, and available when called upon to operate. 6 TR 707. The purchase of the Jackson Gas Plant will also partially replace the capacity that will be lost by the retirement of the Classic Seven and will allow the Company to

continue to lower emissions and capitalize on lower natural gas prices. 6 TR 707. In addition to the operational benefits noted above, Mr. Kehoe also presented a detailed explanation as to how the Jackson Gas Plant's design allows it to take advantage of changing load and market conditions. 6 TR 707-709.

Consumers Energy witness Linda M. Hilbert, the Company's Executive Director of Environmental Services, presented testimony and exhibits to (1) describe the environmental regulations with which the Company's electric generating fleet must comply, (2) explain the cost of compliance with those regulations, and (3) define the timing and justification for the investments made to ensure regulatory compliance. See, generally, 7 TR 1227-1269 and Exhibits A-34 through A-43. Ms. Hilbert is responsible for developing and implementing an environmental management system and compliance program that assures compliance with all environmental regulations and other legal requirements, managing environmental risks associated with operations, and assuring that the Company's capital strategy for environmental compliance is technically sound, economic, and complements the Company's strategy for delivering safe, reliable, and low-cost energy. 7 TR 1227.

The Company's fossil-fueled electric generating units are subject to numerous, complex, and overlapping air regulations intended to reduce the emission of air contaminants. 7 TR 1229. In addition to air regulations, there are also a number of additional environmental regulations related to water and waste. The Company is seeking recovery of costs incurred for compliance with the following regulations:

Air Quality Regulations

	Regulation	Acronymn	Controlled Pollutant	Compliance Date
a.	Clean Air Interstate Rule	CAIR	NOx, SO_2	2009 - 2018
b.	Cross-State Air Pollution Rule	CSAPR	NOx, SO_2	2015
c.	Mercury Air Toxics Standards	MATS	Hg, PM, Acid Gases, Metals	2015
d.	Michigan Mercury Rule	MMR	Hg	2015

Water Quality Regulations

	Regulation	Acronymn	Controlled Pollutant	Compliance Date
f.	Clean Water Act §316(b)	316(b)	Fish Protection	2018-2021
g.	Steam Electric Effluent Guidelines	SEEG	Effluent	2018-2021

Coal Combustion Residuals (Waste) Regulations

	Regulation	Acronymn	Controlled Pollutant	Compliance Date
h.	Resource Conservation Recovery Act	RCRA	Coal Combustion By-Product	2015-2020

See 7 TR 1230. Ms. Hilbert's testimony and exhibits explained, in detail, the Company's compliance plans for ensuring appropriate compliance with these regulations, in a reasonable and cost effective manner. 7 TR 1227-1269 and Exhibits A-34-A-43. The environmental compliance costs presented by Ms. Hilbert are reflected in Company witness Kehoe's Exhibit A-47. 7 TR 1228.

The Company's environmental compliance plans for air, water, and waste regulations provide value for customers. Ms. Hilbert testified:

> "The Company's approach has considered a variety of technologies, deferral of expenditures for as long as possible consistent with the applicable rules, risks associated with relying on and use of emission allowance purchases and the wisdom of retrofitting older, smaller generating units. As noted earlier, our economic analyses indicate that it is not in the best interest of the customers to retrofit the older, smaller coal-fired units at this time.

> The Company is, however, moving forward with environmental control installations on the five larger coal units. When complete, these major investments in emission control technology will provide significant environmental benefits through the significant reduction of SO2, NOx, particulate matter, mercury, metals, acid gases, and other pollutants as well as an enhancement in CCR management, water management, and fish protection. These efforts will improve the quality of life we enjoy in Michigan. These investments also allow the continued operation of 1,250 MW of Michigan-based, coal-fired generation thus preserving the fuel diversity that is necessary to protect customers from significant fuel price fluctuations." 7 TR 1252-1253.

The evidence presented by Ms. Hilbert demonstrates that the Company's environmental compliance strategy reasonably ensures compliance with applicable state and federal environmental regulations, and the investments made to achieve such compliance have been made in a manner which has minimized, to the extent reasonably possible, the associated cost for customers. 7 TR 1254.

c. <u>Areas of Dispute with Staff</u>

(i) Consumers Energy's air quality contingency costs are reasonable and should be included in rate base.

Staff witness Nicholas Evans recommended that all of the projected Air Quality Control Systems ("AQCS") contingency costs should be excluded from rate base in this proceeding, in the amount of $26,804,000 during 2015 and $10,674,000 for the first five months of 2016. 8 TR 1614-1615, 1621; Exhibit S-10.1, columns (d) and (e). Attorney General witness Sebastian Coppola also argued that the Company's AQCS contingency values should be modified so that they are capped at 15% of the project cost. 7 TR 1265; Exhibit AG-12. As explained below, Consumers Energy's AQCS contingency costs are based on industry-accepted methods of projecting such costs, are consistent with industry benchmarking data, are real costs just as the other projected costs in the project budgets, and are a reasonable and prudent component of the

total costs of the AQCS projects. The Commission should approve their inclusion in rate base in this case.

Staff witness Evans' argument that contingency expenditures "may not be incurred at all" (8 TR 1615) fails to recognize that including contingency in project cost is well-established, standard project management methodology and consistent with industry practice. 7 TR 1258. Ms. Hilbert explained on rebuttal:

> "According to the Association for the Advancement of Cost Engineering International ('AACE'), contingency is 'An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs.' [Emphasis added.] Contingency is generally included in most estimates, and is **expected to be expended.** It is a real item in a project estimate like any other cost, and should be included in every estimate of projects of this size. Regarding the Company's performance in this area, the total installed cost of nearly all completed projects has finished very near the approved amount all while delivering the expected results. Those total costs, which include contingency, are consistent with benchmarking data as show[n] in my Exhibit A-43 . . ." 7 TR 1258-1259 (emphasis in the original; footnote omitted).

The AQCS contingency costs are real costs, and it would be inappropriate to exclude them from the project budgets for purposes of determining rate base in this proceeding.

Staff witness Evans' second stated reason for proposing to exclude AQCS contingency costs from the test year rate base was that "if some [contingency] expenditures are ultimately incurred, the final amount could be anything from $1 to the amount projected (or even more)." 8 TR 1615. However, this argument assumes that the Company's projected contingency costs are a simplistic "range of possible spending" which creates a higher degree of uncertainty regarding future expenditures than is found with other cost categories. See 8 TR 1615. This argument and assumption are belied by the detailed and aggressive nature of the way the Company projects contingency amounts. As explained by Ms. Hilbert, each project has a very

specific forecasted contingency that is constantly evaluated and adjusted based on actual risk. Ms. Hilbert testified:

> "[O]ur project 'contingency cost' is a risk-based estimated monetary value based on the Project Management Institute's ('PMI') quantitative analysis of the project's risks and opportunities. Our risk-based contingency value reflects a probabilistic approach tailored to the project and periodic review ensures its relevancy for the phase. We are not using a simple percentage-based approach. To calculate our risk-based contingency, we take the probability of occurrence multiplied by the potential impact. For example, if we have $15 million associated with the procurement of commodities, we may determine that the estimated monetary value of the risk-based contingency to have a 40% probability that prices will rise 10%. We would thus carry $600,000 in risk-based contingency. We could have opted for a simple percentage-based contingency application in the early stages of the project. However, that approach ties up too much capital and requires little analysis of the likelihood of the contingency occurring or the impact of the occurrence of the contingency. Each project has a different percent of contingency which could change over the life of the project depending on what stage the project is in and certainly which will be different between projects. This could result in the perceived assumption that our contingency is a 'range of possible spending' which creates a higher degree of uncertainty regarding future expenditures than is found with other cost categories, as Mr. Evans indicated. In reality, each project has very specific forecasted contingency that is constantly being evaluated and adjusted based on actual risk. We perform routine risk reviews that identify items available for review and audit. This provides greater transparency than a simple percentage-base method and the periodic evaluation throughout the project lifecycle drives continued risk and cost mitigation ideas to help achieve predictable results." 7 TR 1259-1260. See also Exhibit A-95.

Contrary to Mr. Evans' suggestion, the Company's contingency amounts are not simplistic "ranges of possible spending," but instead are project-specific, specifically-analyzed and projected cost amounts similar to any other cost item in the projects' budgets.

Mr. Evans admitted that he did not perform any analysis of the likelihood that any of the contingency costs would in fact be incurred by the Company. 8 TR 1622. Mr. Evans did not

rely on any type of project management resource, authority, or consultation or study of industry standards regarding project management and budget-setting. 8 TR 1622-1623. His recommendation in this case is contrary to the Staff recommendation in Case No. U-17087, in which Staff witnesses Eric Stocking and Shannon Whitton recommended inclusion of projected AQCS contingency costs in rate base. 8 TR 1626. Mr. Evans indicated that he could not recall how the projected contingency costs presented in Case No. U-17087 compared to the actual costs incurred on the AQCS projects since the Company's filing in that case. 8 TR 1626-1627. However, as explained by Ms. Hilbert, the total installed cost of nearly all completed AQCS projects has finished very near the approved amount, including contingency amounts, while delivering expected results. 7 TR 1259. Mr. Evans' proposal on the disallowance of AQCS contingency costs is contrary to industry practice, prior Staff positions, and the proven past accuracy of the Company's projections.

Mr. Evans' third offered justification for his proposal to exclude AQCS contingency costs from rate base is his opinion that "allowing contingency expenditures into rate base may dampen incentives for cost control." 8 TR 1615. This argument fails to properly recognize that contingency costs are an actual cost, analogous to all other categories of projected costs in the AQCS budgets. It is not an accepted industry practice to use contingency or the lack thereof as an incentive for cost control. Mr. Evans' argument on this issue essentially amounts to a contention that the Commission should "incentivize" project cost control by withholding rate recovery of a projected category of costs without any showing or evidence that the Company's projections are inaccurate or unreasonable. The Commission should reject such an unreasonable recommendation. The Company's projections of AQCS contingency costs are reasonable, are

consistent with well-accepted industry best practices, and are a reasonable and prudent component of the total costs of the AQCS projects. 7 TR 1260.

Additionally, Mr. Evans' proposed exclusions from rate base identified above do not recognize or account for the fact that not all of the Company's AQCS contingency costs are included in the Company's requested rate base amount. The Company has instituted measures to review and evaluate contingency costs. 6 TR 720-721. Specifically, the Company has created a line item in each year's budget and the Company's long-term financial plan called the "Blackbox." 6 TR 720. The Blackbox line item is the difference between the estimated cost of the projects the business has requested during the time and the amount of funding authorized by senior management. 6 TR 720. The Blackbox line item also recognizes that individual project contingency dollars, when aggregated, may represent more contingency dollars than are ultimately required. 6 TR 720.

The above process essentially removes a portion of projected contingency amounts and applies an off-setting credit, which corresponds to those removed costs and to the Company's Fossil and Hydro Generation capital request in this case. 6 TR 720. For an example of this process, Company witness Kehoe provided Exhibits A-97 (DBK-7) and A-98 (DBK-8), which identify the removal of projected costs in the amounts of $31.2 million in 2015 and $12 million in 2016. 6 TR 720. The Company uses the Blackbox process to regularly review projects and their associated contingencies. 6 TR 721. Contingency amounts that have a higher degree of probability or risk are left in the project cost estimate. 6 TR 721. Alternatively, contingency amounts that are found to have a lower probability or risk are credited to the Blackbox and removed from projected cost amounts. 6 TR 721. Adoption of Mr. Evans' proposed removal of AQCS contingency costs would be in effect removing contingency costs twice from rate base—

once as part of the Blackbox credit and once as part of Mr. Evans' proposal. This would be unreasonable and should be rejected.

(ii) Consumers Energy's capital expenditures associated with Steam Electric Effluent Guidelines ("SEEG") compliance should be included in rate base.

Staff witness Evans also recommended removing from rate base of the Company's projected test year capital expenditures associated with the proposed EPA's SEEG rule. 8 TR 1617. Mr. Evans based this recommendation upon his opinion that the SEEG rule is too uncertain to warrant investing in compliance measures during the test year. 8 TR 1617. This recommendation does not recognize the necessity of conducting the technology feasibility study and the wastewater study in order to accommodate the development of the least-cost method of complying with the SEEG, and the expedited time period in which those studies must be accomplished in order to achieve regulatory compliance with the SEEG.

The EPA is under court order to complete the SEEG final rule in September 2015. 7 TR 1262. The EPA has stated that the SEEG's new water quality standards will be aligned with the coal combustion residual ("CCR") disposal rules (otherwise referred to as Resource Conservation Recovery Act or "RCRA") and will be completed in 2015. The EPA finalized the RCRA CCR rule on April 24, 2015. 7 TR 1262. The proposed SEEG rule indicates that implementation of SEEG requirements will be required as soon as practicable, beginning with the next National Pollution Discharge Elimination System ("NPDES") permit cycle. 7 TR 1262. Consumers Energy's NPDES permit renewal application is due in early 2016. The finalized RCRA CCR rule's surface impoundment closure requirements and ground water monitoring requirements provide relative certainty that the final SEEG rule will require treatment of CCR wastewaters. 7 TR 1262-1263. It is not only reasonable and prudent, but imperative, to

immediately begin determining how to comply with the RCRA's CCR rule and the SEEG rule in order to be prepared for the early 2016 NPDES permit renewal process. Ms. Hilbert explained:

> "We are confident that the installation of Waste Water Treatment ('WWT') and Dry Bottom Ash ('DBA') handling systems will meet SEEG compliance requirements based on the draft SEEG rule and the final CCR rule. Present work regarding the technology feasibility study and the wastewater study is necessary to accommodate the development of a least-cost design, engineering, and construction of the technologies to meet the NPDES permit renewal application and expected operational compliance dates. These studies consist of a comprehensive economic evaluation of DBA handling systems and potential WWT, wastewater reduction, and reuse systems to identify the most feasible and economic treatment options compliance strategy for the anticipated SEEG requirements. In the Bottom Ash Study, HDR, Inc. evaluated several different technologies for bottom ash handling and developed cost estimates for submerged flight conveyors, as this appears to be the EPA's preferred option (proposed option 4a). The Regulated Wastewater Relocation Study, which is currently underway, is evaluating the feasibility to optimize the reduction, reuse, and treatment of existing NPDES regulated wastewater streams that will be eliminated or rerouted because of SEEG rulemaking impacts at the DE Karn and JH Campbell Generating Plants. This study is anticipated to be finalized in the fall of 2015 in prudent preparation for the final SEEG rule in September 2015 and quick decision making needed for a NPDES permit renewal application in early 2016." 7 TR 1263.

Staff witness Evans admitted that his recommendation to not include SEEG compliance costs for purposes of ratemaking in this proceeding is based on his opinion that the Company should "wait and see" what version of the SEEG rule is finalized in September of 2015. 8 TR 1628. However, he also testified on cross-examination that the Company should not stop incurring costs related to SEEG compliance and undertaking activities related to that compliance during the period before the SEEG rule is finalized. 8 TR 1629. Mr. Evans testified that in his opinion, the Company should continue to engage in preparatory activities and incur costs related to SEEG compliance but not be allowed rate recovery for such compliance activities and costs. *Id.* Mr. Evans testified as follows:

"Q. Is it your opinion that the Company should wait and see what version of the SEEG rule the EPA adopts before planning to implement a compliance strategy?

"A. Yes.

"Q. Is it your opinion that the Company should incur no costs on SEEG compliance until the EPA finalizes the SEEG rule?

"A. No. My testimony is that recovery from – of –excuse me. Recovery of projected expenditures from ratepayers should not occur until the SEEG is finalized.

"Q. Even though the Company will have to incur costs before the rule is finalized?

"A. Yes." 8 TR 1628.

The Company submits it would be unreasonable and unlawful to deny Consumers Energy recovery of costs of regulatory compliance which no party to this proceeding disputes will have to be incurred in order to achieve compliance with SEEG.

Mr. Evans did not offer an opinion as to what version of the proposed SEEG rule the EPA will likely adopt. He testified that he did not know if the Company would be able to comply with Option 4a of the SEEG rule on the effective date of SEEG if the Company stopped its compliance activities which are designed in light of the Company's expectation that Option 4a is the EPA's preferred SEEG rule. 8 TR 1629-1630. Mr. Evans testified that he had not analyzed the possibility of noncompliance with SEEG, or the possibility that the Company's compliance costs would increase if it did not plan to comply with Option 4a and that Option was implemented by the EPA. 8 TR 1630. In short, Mr. Evans provided no evidence which supports his speculation that Option 4a may not be the EPA's preferred SEEG rule. It would be unreasonable and imprudent for the Company to stop incurring costs associated with ensuring it

complies with the SEEG, as suggested my Mr. Evans' ratemaking proposal. The Company should be allowed to recover these reasonable and necessary costs.

Ms. Hilbert summarized the reasonableness of the Company's proposed SEEG expenditures and the necessity of incurring them to achieve regulatory compliance as follows:

> "While the SEEG rule is not currently finalized, the EPA is under court order to complete the SEEG final rule in September 2015. This timeline leaves the Company with approximately six months to incorporate the compliance plan into the NPDES permit renewal in early 2016. Those six months, which occur over the winter months when testing cannot occur, simply do not provide enough time to test, design, and engineer a compliance plan. The test year is exactly when we need the funding in order to be compliant with this rule given the permitting schedule. We cannot wait for the rule to be final and simply hope to be in compliance by the timelines required, as suggested by Mr. Evans' recommendation. Given the EPA's insistence that SEEG will align with the finalized RCRA, we are certain that at a minimum, some form of WWT and DBA handling will be required. The Company is taking a reasonable, prudent and proactive approach by conducting studies from a technology perspective as well as ways to optimize the reduction, reuse, and treatment of existing NPDES regulated wastewater streams that will be eliminated or rerouted because of SEEG rulemaking impacts. By exploring the various options, the Company will be positioned well to quickly execute an optimal, lower cost SEEG environmental compliance plan." 7 TR 1264.

The Commission should include the SEEG compliance costs in rate base in this proceeding.

d. Areas of Dispute with the Attorney General

Attorney General witness Coppola's recommendations which reduce the Company's Fossil and Hydro Generation expenditures by $40.6 million should be rejected by the Commission. 10 TR 2309-2312. Mr. Coppola's recommendations, which contest expenditures at the Company's Karn Plant, Campbell Plant, Jackson Gas Plant, and certain Air Quality and Other Environmental expenditures, lack adequate evidentiary support, ignore evidence provided by the Company, and disregard basic concepts of ratemaking.

First, Mr. Coppola's complaint that there is "no specific work or equipment" associated with $5 million in projected expenditures at Karn Units 3 and 4 is untrue. 10 TR 2310. Exhibit A-47 (DBK-4) included the $5 million in the 2013-2018 Fossil and Hydro Generation capital expenditures. 6 TR 729. Mr. Kehoe explicitly explained how that amount would be incurred as follows:

> "Q. Is there specific work or equipment associated with this amount?
>
> "A. Yes. The $5 million will be incurred as follows: $652K – Rectifier/Voltage Regulator – unit 3; $1.336 million – DCS Controls Update 1-4; $700K – K4 L-1 Blade Replacement; $1.535 million – DCS Controls Update; and $777K – Replace HP Turbine 1st Stage Blading." 6 TR 729.

Thus, as established above, the Company did include the amounts related to the Karn units 3 and 4 expenditures in Exhibit A-47 (DBK-4) and has provided specific work and equipment related to these expenses. Mr. Coppola's criticisms are unsupported and should be rejected.

Second, there is no merit to Mr. Coppola's allegation that the Company has incorrectly scheduled capital projects at the Campbell plant during the first five months of 2016 and related $8 million reduction to the Company's capital expenditures.[6] 10 TR 2310. Contrary to Mr. Coppola's arguments, the projected capital expenditures that the Company will incur in the first five months of 2016 directly correspond to a scheduled 79-day outage which will occur at Campbell unit 3 beginning March 12, 2016. 6 TR 730-731. Mr. Kehoe explained that it is good practice to schedule maintenance work during scheduled outages, when possible, because it avoids unnecessary disruptions in generation or generation derates. 6 TR 730-731.

[6] Mr. Coppola also requests a $6.3 million reduction in relation to "$15 million of unspecified expenditures" at Campbell unit 3. 10 TR 2310. However, the Company has not proposed any unspecified $15 million expenditure at this unit. 6 TR 731. To the extent that Mr. Coppola intended to direct this recommendation at the $15 million expenditure at Karn units 3 and 4, it is incorrect that this amount was unspecified. 6 TR 731. The Company has included this amount in Exhibit A-47 (DBK-4) and Mr. Kehoe has fully explained the components of this expenditure in his testimony. 6 TR 732.

Alternatively, Mr. Coppola's recommendation, which would spread maintenance activities throughout the year regardless of scheduled outages, would increase power supply costs by creating more outages and instances where the Company's generation would be unavailable and derated.

Next, Mr. Coppola proposes a reduction of $4.8 million to capital expenditures at the Jackson Gas Plant on the basis it is "surprising" that "capital improvements" would be needed during the first five months of 2016. 10 TR 2311. The $4.8 million of projected capital expenditures at the Jackson Gas Plant does not relate to "capital improvements" as Mr. Coppola suggests. 6 TR 732. Rather, these amounts are related to an LTSA with GE at the Jackson Gas Plant. 6 TR 732. Exhibit A-108 (DBK-18), Company discovery response 17735-ST-CE-38, identifies that the use of an LTSA is common practice, ensures that maintenance is performed at specific milestones, and that parts are available for the life of the agreement. 6 TR 732-733. As such LTSA's are common practice for generating units and as the amount projected by the Company do not result in capital improvements, Mr. Coppola's unsupported and speculative recommendation should be rejected.

Finally, Attorney General witness Coppola proposed a reduction in AQCS contingency costs in his Exhibit AG-12. Mr. Coppola proposed applying a straight 15% contingency to the projects that were forecasted to have greater than a 15% contingency. 7 TR 1266. The Commission should reject this simplistic approach. Ms. Hilbert explained that the Company's method of forecasting contingency costs is a risk-based estimated monetary value that is based on a quantitative analysis of the project's risks and opportunities. 7 TR 1265; Exhibit A-95. Applying a simplistic 15% limit as an across-the-board contingency factor would tie up too much

capital and would provide little substantive analysis on true contingency risk. 7 TR 1265. Ms. Hilbert testified:

> "Consumers Energy's methodology for projecting contingency costs reflects established and accepted industry practice, and the contingency costs are a reasonable and prudent component of the total costs of the AQCS projects. Mr. Coppola proposed applying a straight 15% contingency to the projects that were forecasted to have greater than 15% contingency. Mr. Coppola inconsistently failed to increase the contingency of projects that were forecasted to have less than 15% contingency. Mr. Coppola's proposal would, in essence, create a 'cap' on allowable contingency. We believe having a cap on contingency would discourage active management of ever changing contingency risks. As previously stated, the Company routinely performs risk reviews on these projects and is constantly looking for cost avoidance opportunities on the contingency amounts as well as the entire project." 7 TR 1266.

Mr. Coppola provided no substantive analysis of any of the contingency amounts contained in the project budgets presented by Ms. Hilbert in this case. The Commission should reject his unsupported cap on contingency costs to be included in rate base.

Mr. Coppola's reduction to Air Quality capital expenditures also fails to recognize the purpose and common industry practice of using contingency costs and also fails to consider the Company's use of the Blackbox line item which off-sets certain contingency costs prior to the Company's filing. 6 TR 734. Company witness Kehoe testified that the contingency portion of the Company's Air Quality capital expenditures totals 15% of those expenditures. 6 TR 718. That amount is reduced by the Blackbox credit, which is explained above. 6 TR 719-721. Reducing the contingency portion of the Air Quality capital expenditures even more as proposed by Mr. Coppola would have the effect of removing contingency expenditures twice, and would be inappropriate.

Further, Mr. Coppola's reduction of $4.8 million of Other Environmental capital expenditures incorrectly assumes that these costs have been wrongly included in the first five

months of 2016. 6 TR 734-736. Other Environmental expenditures are not incurred by the Company evenly throughout the year. 6 TR 735. A significant portion of the Company's Other Environmental spending is related to one-time projects such as the design and construction of an ash cell and new catalyst management for the Campbell site. 6 TR 735. Since these costs are not incurred evenly throughout the year, Mr. Coppola's recommended straight-line allocation, and corresponding reduction, should be rejected.

As a result of the above evidence, Mr. Coppola's proposed reductions to the Company's Fossil and Hydro Generation capital expenditures should be rejected in their entirety.

e. Areas of Dispute with Michigan Environmental Council ("MEC")/Natural Resources Defense Council ("NRDC")/Citizens Against Rate Excess ("CARE")

MEC/NRDC/CARE witness Dan Koehler criticizes the Company's projection of Fossil and Hydro generation capital expenditures that will be incurred after the test year period, expenditures related to a future plant at Thetford, and fuel supply arrangements at the Jackson Gas Plant. 10 TR 2394-2396. These criticisms, however, should be rejected by the Commission as they are the result of incomplete and flawed analysis.

Mr. Koehler's suggestion that the Company "failed to provide sufficient information" to support capital expenditures beyond the test year is incorrect. 10 TR 2395. The Company provided 2016, 2017, and 2018 Fossil and Hydro Generation plant capital expenditures in Exhibit A-47 (DBK-4) for the purposes of recovery through the proposed IRM. 6 TR 735. With this information, the Company also provided the Company's long-term financial plans, which include detailed cost projection and project numbers. 6 TR 735; see, Exhibits A-98 (DBK-8), A-101 (DBK-11) through A-107 (DBK-17). This detailed and extensive information more than addresses each project and more than sufficiently supports the Company's projected capital

expenditures during the time period in question. Mr. Koehler's arbitrary and factually incorrect conclusion that the Company's presentation of information was insufficient should be rejected.

Mr. Koehler's criticisms regarding the recovery of expenditures related to a future plant at the Thetford site (10 TR 2414) also lack merit. Through the IRM, the Company has proposed future recovery of $10 million related to costs that will be incurred related to the permitting, designing, and engineering requirements of a future generating unit at Thetford. 6 TR 736. By requesting this amount, the Company is not seeking costs related to constructing a new generating unit. 6 TR 736. Rather, these costs are related to the early stages of the Company's efforts to address future capacity needs. 8 TR 1525. To maintain the option of a generating unit at the Thetford site, certain expenses will need to be incurred so that a credible alternative exists for potential contract negotiations or future solicitations. 8 TR 1525.

In addition to the above, Mr. Koehler presents "concerns" regarding a fuel supply plan for the Jackson Gas Plant and potential pre-approval of possible transportation agreements should be rejected by the Commission. 10 TR 2427-2428. As an initial matter, the Company does not own the Jackson Gas Plant. 6 TR 736. The sale of the plant is expected to close shortly after the Order in this case. 6 TR 736. Once the Company takes ownership and begins operating the plant, the Company will address any necessary fuel supply arrangements. Moreover, fuel supply arrangements are germane to Power Supply Cost Recovery ("PSCR") proceedings conducting pursuant to 1982 Public Act 304. 6 TR 737. It is in those proceedings where issues concerning fuel supply and transportation agreements should properly be considered.

3. Information Technology ("IT") Capital Expenditures

a. Company's Position

Company witness Christopher J. Varvatos, Executive Director of the IT Department, testified to the necessary capital expenditures for the IT Department, which was formerly known

as the Business Technology Solutions ("BTS") Department. 6 TR 831. Exhibit A-71 (CJV-3) provides the electric and common capital expenditures for the years 2013 through 2018. 6 TR 845. The Company's IT capital expenditures are reasonable and prudent. In order to minimize costs and maximize value, the Company competitively bids contracts, continuously evaluates business requirements, and aggregates purchases to maximize volume discounts when practical. 6 TR 862. These measures are preformed to control costs and ensure efficient delivery of effective technology solutions. 6 TR 862.

The IT Department's capital expenditures are for Software Application Projects and Asset Management expenditures. 6 TR 845-862. The Software Application Projects include Field Mobility, Customer Value Initiative, Bring Your Own Device, Business Partner Functionality, Cyber Security, SAP Enhancements, Obligation to Serve, and Technical Architecture. 6 TR 848-850. The details of each of these programs are explained and supported in detail in Mr. Varvatos' testimony. 6 TR 848-861. The Software Application Projects are investments that are designed with the express purpose of addressing specific business needs, enhancing workforce communications and productivity, and improving customer service. 6 TR 861-862.

The Asset Management expenditures consist of the investments required to provide a secure and reliable computing infrastructure. 6 TR 846. These investments are designed to minimize costs by replacing assets that are at the end of their useful life before significant repair costs or business impacting outages occur. 6 TR 846. There are two major projects included in these expenditures: Field Services Solution and Call Center Infrastructure Refresh. The Field Service Solution project replaces the outdated Order Management and Routing System with mobile applications and devices. 6 TR 846-847. This project will increase the productivity of

field employees and improve the applications for schedulers, dispatchers, and field leaders. 6 TR 847. The Call Center Infrastructure Refresh project is a comprehensive replacement of the major components of the Company's five call centers that are outdated. 6 TR 847. Completion of this project is necessary to ensure that the Company's call centers are available to take customers' calls on a day-to-day basis. 6 TR 847.

b. Response to Staff

Staff did not propose any disallowances to any of the Company's proposed IT capital expenditures. See Exhibit S-2, Schedule B3. Staff accepted the Company's proposed O&M expenses and capital expenditures related to cyber security recognizing the growing need to invest in cyber security to ensure safe and reliable service. 10 TR 2129. Additionally, Staff witness Brian Sheldon recommended that the Commission require Consumers Energy to file an annual report on the Company's cyber security program. 10 TR 2129-2130; see also Exhibit S-14.0. The Company generally agrees with the Staff's proposed annual report. 6 TR 866. While the Company is interested in keeping the Commission informed regarding its actions on cyber security, Consumers Energy also needs to ensure that certain information remain protected. 6 TR 866-867. Thus, the Company is willing to provide the information requested in the Staff's proposed report, but in order to assure information remains protected will need flexibility and discretion with respect to how the information is provided. 6 TR 866.

c. Response to the Attorney General

The Commission should reject the Attorney General's proposed $22.5 million reduction to the IT Department's proposed capital expenditures. Mr. Coppola proposed disallowing $8.7 million from the Call Center Infrastructure Refresh project and $13.8 million from

Miscellaneous Software Applications. 10 TR 2313-2314. These proposed disallowances are unsupported and fail to recognize the reasonableness of the Company's expenditures.

The Call Center Infrastructure Refresh project is critical and necessary. The purpose of the Call Center Infrastructure Refresh project is to replace equipment which is at the end of its useful life and is technically out of date. 6 TR 869-870; Exhibit A-119. Company witness Varvatos testified, "Completing this project will ensure that the Company's call centers continue to be available to take customers' calls on a day-to-day basis and are able to accept and respond to the significant call volume increases during storms and emergency situations." 6 TR 847.

The Attorney General offers two criticisms of the Call Center Infrastructure Refresh project. As justification for his proposed disallowance, Mr. Coppola contended that the Company neglected to support this project and indicated that implementation of the project has been delayed into the second half of 2016. 10 TR 2313. These assertions are incorrect. The Call Center Infrastructure Refresh project will be substantially completed during the test year. 6 TR 847. As was indicated to the Attorney General during discovery (see Exhibit A-119), the project has an implementation date of June 30, 2016, which is when the new equipment will be available for use. 6 TR 869. Thus, the project's expenditures are being incurred during the projected test year. 6 TR 869.

Further, it is disingenuous for the Attorney General to assert that the project was unsupported. The Company provided Mr. Coppola with hundreds of business case files for the Company's IT capital projects, including Call Center Infrastructure Refresh. 6 TR 870-871. These files contained a significant amount of information regarding the project, and further supported the Company's need to replace technically out-of-date equipment. 6 TR 870-872. Attorney General witness Coppola's proposed disallowance puts the Company at risk for call

center failure. The Call Center Infrastructure Refresh project is necessary for the continued, reliable operation of the Company's call centers, and the record evidence establishes that the expenditures are reasonable and prudent.

Additionally, the Attorney General proposed to disallow $13.8 million from software projects that he labeled "Miscellaneous Software Applications." Mr. Coppola recommended delaying or reevaluating the Contract Lifecycle Management project, High Performance Analytic Appliance, Customer Relationship Management, Bring Your Own Device, 800 MHz Tower Connectivity Optimization, Business Intelligence Reporting Improvements, Storage Refresh and Redesign for Next Generation Storage, and Upgrades and Replacements. 10 TR 2313-2314. This recommendation ignores the extensive testimony provided by Company witness Varvatos supporting these projects. 6 TR 848-862, 872-882.

Moreover, Mr. Coppola failed to support his proposed disallowance. Although there are a number of projects that he recommends de-funding, the only specific reason provided was related to one project, the 800 MHz Tower Connectivity Optimization project. Mr. Coppola argued that "[i]n some cases, such as the upgrading of the current radio communication system, it seems unnecessary to spend money on such a project if the Company is developing a field connectivity system that uses cellular devices." 10 TR 2313-2314. However, upgrading the radio communication system is necessary. Company witness Varvatos explained, "The Company's need to rely on its 800MHz system for emergency communications has been demonstrated repeatedly over the years. In emergency situations, the Company cannot exclusively rely on cellular communications with its field workers." 6 TR 874. While cellular devices have many benefits including increasing productivity, these devices are not reliable during times of emergencies. 6 TR 874. The 800 MHz Tower Connectivity Optimization

project maintains the radio communication system so that both day-to-day and emergency communications between dispatchers and work crews can reliably occur. 6 TR 874. As such, the Attorney General's proposed disallowance should be rejected.

4. Smart Grid ("SG")/Advanced Metering Infrastructure ("AMI") Capital Expenditures

a. Introduction and Summary of SG/AMI Meter Installation Status

The SG/AMI Program represents a key initiative in Consumers Energy's overall business strategy. The Consumers Energy SG/AMI Program was established in 2007 with the primary focus on developing and installing an AMI. 6 TR 934. Company witness Lincoln D. Warriner, a Senior Regulatory and Business Analyst in the Smart Energy Financials Department, testified concerning the SG/AMI Program. 6 TR 931-983. The AMI system includes electric meters and gas meter modules capable of transmitting and receiving data ("smart meter"), a two-way cellular point-to-point communications network, system integration to support the use of the data for billing and operational uses, and a customer interface/web portal. AMI enables and promotes various new beneficial customer programs and billing options for electric and electric/gas combination residential, commercial, and industrial customers who have a smart meter installed. 6 TR 935.

Smart meter installation began in August 2012, and the installation is projected to be completed during 2017. 6 TR 935.[7] Mr. Warriner explained that in addition to the installation of smart meters, significant systems work is required to enable smart meter functionality and to achieve the benefits of the AMI Program. 6 TR 937-938. Pursuant to the Commission's direction in Case No. U-17000 (Order dated September 11, 2012, page 5), Consumers Energy offers customers an option to opt out of receiving an AMI smart meter. 6 TR 939.[8] As of November 2014, the customer acceptance rate of smart meters is 99.54%, which means that only 0.46% of customers in areas in which AMI meters have been installed have opted out of the AMI Program. 6 TR 939.

b. AMI Capital Costs

Mr. Warriner explained that the total capital investment for the AMI program, which will occur over the period from 2007-2019, will be approximately $750 million. 6 TR 939. This investment includes the purchase, testing, processing, and installation of electric smart meters and gas meter modules, the enabling systems and infrastructure and design, pilot and implementation of customer programs. 6 TR 939. The electric portion of this total capital investment is approximately $662.5 million for the period 2007-2019. 6 TR 939-940; Exhibit A-76, page 1, line 6, columns c-o. Mr. Warriner's Exhibit A-74 sets forth the projected electric

[7] In an Order issued September 26, 2014 in Case No. U-17057, the Commission stated that 850,000 AMI meters should be installed by year-end 2015, or the temporary waiver for electric meter testing granted in that case would be rescinded for 2016 and 2017. Mr. Warriner explained that the 2015 year-end installation figure of 850,000 referenced in the Case No. U-17057 Order is based on an assumption of an even distribution of meter installations from the date of the Case No. U-17057 Application (August 8, 2014) through 2015. 6 TR 936. Mr. Warriner explained that the installation schedule included in the Company's most recently approved gas rate case, Case No. U-17643 and in this electric rate case reflects updated plans to have 754,693 AMI meters installed at the end of 2015, with higher installation rates planned for 2016 and 2017 to complete the installation of the smart meters. 6 TR 936. Mr. Warriner explained that the meter installation plan included in this case and in Case No. U-17643 coordinates the completion of system development and integration work with the accelerated completion date of AMI meter installations (the Company moved the completion date from 2019 to 2017). 6 TR 935-937. The Company respectfully requests the Commission to recognize the smart meter installation plan included in this case and grant the Company a waiver of the electric meter testing requirement through 2017. 6 TR 937.

[8] The charges associated with the AMI Opt-Out tariff are discussed in detail below in section VIII. B. 9. of this Brief.

and common capital expenditures for the smart energy program. 6 TR 940. These capital expenditures include field equipment/facilities, meters, software/systems development, SG infrastructure, and program engineering/design and management. 6 TR 940-942. The AMI capital investments which should be approved to be included in rate base through the test year ending May 31, 2016 total $296,485,000. Exhibit A-74, line 6, sum of columns (b), (c), (d), and (e). The smart energy capital amounts which should be included in the Company's proposed IRM are $105,614,000 (2017) and $12,514,000 (2018), respectively. Exhibit A-74, line 6, columns (g) and (h).

c. <u>AMI Benefits</u>

Mr. Warriner explained the numerous benefits the AMI program provides customers, testifying:

> "The AMI Program provides the foundation for many other customer and Company benefits that improve the efficiency, reliability, economics, and sustainability of the electric system. The use of AMI data empowers customers to make informed energy and cost-saving decisions about their energy consumption, improves operational efficiencies, and enhances Consumers Energy's analytics relating to energy needs and service interruptions, and supports connection of new resources to the grid. These benefits are recognized by experts independent of Consumers Energy, as noted in MPSC Staff witness Shannon M. Whiton's direct testimony in Case No. U-15645 (AMI remand), 1 TR 317 (transcript of May 5, 2014 remand evidentiary hearing):
>
> > ' . . . the new meters improve customer service through an increased accuracy of meter reading and billing. The new meters shorten outage times with improved outage detection. Furthermore, the new meters and ancillary components enable the Company to provide customer rate incentives to voluntarily reduce their energy use at peak times through a dynamic peak pricing program or participation in a voluntary direct load management program. Participation in these programs allows customers to make informed cost-saving decisions

> about their consumption. All of these benefits add convenience and improve electric service for Consumers Energy's customers and the shorter outage times may be lifesaving for customers who have lost their power.'" 6 TR 947-948.

Mr. Warriner articulated in detail and quantified major benefits provided by the AMI Program, including automation of meter reading and resulting reduced meter reading expenses, improved meter read accuracy and reduced number of estimated bills, improved theft detection, increased customer access to detailed energy usage web portal and energy efficiency services, enabling customer programs such as dynamic pricing, direct load administration ("DLA"), Pay As You Go, and the option for customers to select their own bill payment due date, the enablement of new rate options and energy consumption information that supports customer efforts to manage their energy usage and costs, improved outage management and reduction in outage times, and improved operational efficiencies provided by the AMI-enabled remote turn-on/turn-off capability. 6 TR 948-950.

d. Cost-Benefit Net Present Value ("NPV") Analysis

Mr. Warriner's Exhibit A-76 provides Consumers Energy's AMI business case and sets forth both the costs and benefits for both electric only and combination electric/gas combination customers for the 2007-2032 time period. 6 TR 943. The business case provides a NPV of the net benefits the AMI Program provides customers. 6 TR 943.[9] The NPV calculation in the business case is based on tested assumptions for both costs and benefits that are updated as the program progresses. 6 TR 943. The current AMI Program net present value of revenue requirements ("PVRR") shows savings to customers of approximately $24.5 million (a reduction of $24.5 million in NPV revenue requirements). 6 TR 944; Exhibit A-76, page 5. The electric

[9] The Company's NPV analytical approach can also be described as the "present value of net revenue requirements," or PVRR. 6 TR 943.

net PVRR for electric customers is a reduction of $15.2 million in NPV revenue requirements. 6 TR 944; Exhibit A-76, page 6.[10] The customer benefits which are quantified in the Company's AMI business case analysis are in addition to the qualitative benefits for customers also made possible by AMI, described above. The NPV cost-benefit analysis set forth on Exhibit A-76 demonstrates the projected rate impact of the entire AMI program will be a lower cost of service for customers than if the AMI program were not implemented. The analysis set forth in Exhibit A-76 demonstrates the continued reasonableness of the AMI program.

The Commission has approved cost recovery for AMI costs in several electric rate cases beginning with Case No. U-15645, a rate case which Consumers Energy filed in November of 2008. See, Case No. U-15645, Orders dated November 2, 2009, pages 58-59 and October 7, 2014, pages 15-16; Case No. U-16191, Order dated November 4, 2010, pages 18-20; Case No. U-16794, Order dated June 7, 2012, page 31; and Case No. U-17087, Orders dated May 15, 2013 and May 15, 2013, page 8. Although the Company's NPV cost-benefit business case analysis for the AMI Program continues to demonstrate a net revenue requirement reduction for customers which results from implementation of the AMI Program, the Company submits that the standard for determining the appropriateness of cost recovery for the program should be whether investments in the program are reasonable and prudent, which is the standard employed for other utility investments. The Company requests the Commission find that the Company does not need to submit a NPV cost-benefit business case analysis in future rate cases which include requests for AMI cost recovery, and to instead find that such requests will be judged based on the

[10] Mr. Warriner explained that the net PVRR reflected in the AMI business case presented in this case has changed from the AMI business cases presented in Case No. U-15645 (remanded AMI electric rate case proceeding) and Case No. U-17643 (Consumers Energy's most recent gas rate case) largely because of the acceleration in the meter implementation schedule, changes in the outlook for summer peak generation capacity prices used to calculate the customer benefits related to the AMI-enabled DLA and Dynamic Peak Pricing Programs, and changes in estimates of O&M costs associated with the AMI-related customer programs. 6 TR 944-945.

regularly-used reasonable and prudent standard. The Company's request for recovery of AMI investments in this proceeding meets this standard, in addition to meeting the NPV cost/benefit analysis standard, and should be approved.

e. Staff's Proposed Disallowance of Investments in Direct Load Administration Switches Should be Rejected

Staff witness Laruwe recommended that the Commission disallow the costs associated with the Company's DLA Program, which involves the installation of AMI-enabled switches to directly control the load of central air conditioners for participating customers during defined peak load events. 9 TR 1912-1921; 6 TR 965. Mr. Laruwe's proposed disallowance is based on his opinion that the Company's DLA Program is unreasonable based on his opinion that a better option would be to implement a smart thermostat based load control program. 9 TR 1925. As explained below, although the Company appreciates Staff's support for furthering demand response technologies in order to fully utilize the opportunities provided by the AMI Program, the disallowance of the DLA switch investment should be rejected.

Mr. Warriner explained the Company's DLA switch process as follows:

> "The Company has designed business processes that utilize the Zigbee communications protocol to deliver cycling signals from a demand response management system to individual central air conditioning switch devices, and also deliver a confirmation back to the demand response management system that the device has received the initial signal and responded. This two-way communication approach provides the Company with timely feedback after demand response events to confirm that targeted load reductions are actually realized. The business processes have been developed considering the potential future addition of new compatible thermostats or other devices, but for the reasons described in this testimony, the Company believes that air conditioning switch devices are a critical first step in the implementation of demand response in our service area." 6 TR 966.

Electric utilities have used load control switches on central air conditioning equipment for many years to successfully reduce demand for reliability and economic purposes on peak days. 6 TR 967.

Mr. Laruwe based his proposed disallowance on a description which he termed a "benchmarking" of 13 thermostat programs offered by seven electric utilities. 9 TR 1913-1917. However, Mr. Laruwe did not recommend a thermostat program. His analysis contained no details about the current or projected peak demand reductions that would be realized by the thermostat programs, and contained no cost analysis of the thermostat programs. He did not address implementation issues such as whether the thermostat would be the property of the homeowner or the utility, or whether incentives would be appropriate to encourage customer acceptance of the smart thermostats. He also did not provide estimates of the benefits which could be realized from a thermostat program. Mr. Laruwe's conclusion that the benefits of a thermostat program would likely be higher than those provided by the Company's DLA switch program were generic and unsupported by any quantitative analysis.

In contrast, the Company's DLA Program is based on robust study and analyses. Mr. Warriner testified:

> "The Company has conducted pilots to determine the peak demand reductions that can be expected with the implementation of direct air conditioning control programs and Dynamic Peak Pricing ('DPP') programs. The results of those pilots were provided in June of 2011 by Company witness Stephen T. Hirsch in Case No. U-16794. Those pilot studies, as well as the advice of industry experts in demand response, have informed and validated the Company's projections of the expected peak demand reductions that can be achieved as part of our implementation of AMI. In fact, the Company's cost-benefit analysis for AMI is conservative with regard to peak demand benefits because we have not projected any incremental benefits that would be expected when combining a DPP rate structure with an enabling technology such as an intelligent programmable thermostat. The Company has also

> not included any costs associated with intelligent communicating thermostats ('ICTs') or other DPP enabling devices in its cost-benefit analysis, and similarly, has not requested cost recovery for those devices in this case." 6 TR 968.

In addition, the Company is investigating the use of Intelligent Communicating Thermostats ("ICTs"). Mr. Warriner explained:

> "[T]he Company has tested an ICT in the 2011 DPP pilot. The results of the pilot indicate that the DPP price is a primary driver of demand reduction at the time of a critical peak event, and that an ICT helps DPP customers realize some incremental improvement in peak reduction over those customers that participate in DPP without an ICT. However, for customers that remained on a standard residential rate, the communication of critical peak information through a web portal application had the same effective load reduction as providing a customer with an ICT.
>
> The Company does have energy efficiency rebate programs currently in place that help offset the initial costs of thermostat upgrades for homeowners. A $10 programmable thermostat rebate is offered to gas customers, and $50 rebates are offered to electric and/or gas customers who install Wi-Fi-enabled thermostats. The Company also provides thermostat upgrade incentives to customers through the Home Performance with Energy Star Program. To date the Company has encouraged the installation of 62,910 thermostat upgrades through these energy efficiency measures.
>
> The Company is also testing Wi-Fi-enabled thermostats to determine the energy savings potential these devices would provide in our service area. There are 352 participants in this pilot test, and models from three manufacturers are being tested. Based on communications that our Smart Energy Efficiency Solutions group has had with manufacturers of ICTs, most thermostats installed as part of a utility demand response program are one-way programmable paging units. We estimate the installed saturation of ZigBee enabled thermostats used for demand response from active manufacturers nationally to be approximately 110,000 units to date, and Wi-Fi-enabled demand response enrolled thermostat saturation from primary retail manufacturers to approximately 35,000 - 40,000 units." 6 TR 968-969 (footnote omitted).

Thus, the Company is proceeding to attempt to implement the ICT technology which Mr. Laruwe desires.

Mr. Laruwe's proposed disallowance based on his preference for ICT technology does not acknowledge the uncertainty which currently exists with that technology. The specific thermostat that was tested in the DTE Energy Company's ("DTE") Dynamic Peak Pricing ("DPP") pilot for that utility's service area is not currently available to the mass market. DTE has also indicated that manufacturers continue to explore the connectivity between home energy management and mobile devices, and that a growing number of energy management software and devices are appearing in the marketplace. In comparison, there are millions of central air conditioning load control switches in use in the United States, and the Company's DLA Program allows those loads to be controlled to provide peak load savings. 6 TR 970.

Another area of uncertainty with regard to thermostat control programs is the longevity of the peak demand savings after the acquisition and installation of the thermostat. Information from other utilities indicates that thermostats have an average useful life of approximately seven years, where air conditioning switches can operate reliably for 25 years. 6 TR 970. The Company is also concerned that the type of thermostats suggested by Mr. Laruwe may limit the number of customers that could participate in a peak load demand response event to only those customers that have an in-home wireless internet connection. The advantage of a central air conditioning switch load control program is that all central air conditioning customers will be eligible to participate. 6 TR 970.

Utilities have experienced higher failure rates with thermostats than with central air conditioning switches. The Company believes that customers are more likely to utilize load control event opt-out features with a thermostat than with a load control switch. This is because

most customers who participate in an air conditioning load control switch program usually do not notice when the air conditioner is being cycled. 6 TR 970-971.

Direct load control switches installed on central air conditioning equipment have proven to provide reliable load reductions over several years at other utilities in the United States, and the solution the Company is proposing utilizes two-way communication that provides strong confirmation regarding what load is available and the response to a load control signal. 6 TR 971. In contrast, direct control of window or room air conditioners is a newer approach to demand response. 6 TR 971. Direct load control switches offer the most certainty and best value for customers. 6 TR 971.

Staff does not dispute the underlying assumptions and benefits provided by the Company's DLA Program. 9 TR 1926. As explained above, the DLA Program will provide peak load savings which will benefit customers, and the costs of the DLA Program are reasonable. The Company is piloting and pursuing further programs which use ICT technology to provide additional benefits, but has not requested cost recovery for those ICT programs in this proceeding. The Commission should reject Staff's proposed disallowance of the costs of the DLA Program, especially in light of the fact that Staff included no costs for the thermostat programs it contends would be preferable to the DLA Program. See 9 TR 1929. The ICT programs desired by Staff have not been sufficiently studied to warrant replacing the DLA Program in favor of an ICT Program. AMI-enabled ICTs and other new technologies represent future opportunities to extend customer benefits beyond those included in the Company's current AMI business case. 6 TR 972. This does not change the fact that DLA switches are a reliable and predictable source of load control and will continue to be so for years to come.

f. The Attorney General's Opposition to AMI Cost Recovery Should be Rejected

Attorney General witness Coppola opposed recovery of any of the capital costs of the Company's AMI Program. 10 TR 2315-2323. However, as explained above, the AMI Program costs are reasonable and prudent, and provide benefits to customers. The Company's projections of benefits are supported by pilot study results, industry studies, consultation with experts, and industry benchmarking. 6 TR 977. Mr. Warriner explained that the Company estimated the benefits provided by AMI conservatively. 6 TR 977-979. The Commission should reject the Attorney General's unsupported[11] criticism of the investments in AMI, and his proposal to deny or defer recovery of those reasonable and prudent investments made to serve customers. The Attorney General has presented no new evidence or argument on the issue of AMI cost recovery in this case which would warrant the Commission adopting his positions on this issue, which were correctly rejected in Case No. U-15645 (Order dated November 2, 2009, pages 58-59 and Order dated October 7, 2014, pages 15-16) and Case No. U-17087 (Order dated June 28, 2013, pages 8-9).

5. Accumulated Provision for Depreciation

The depreciation reserve balance for the projected test year is developed by applying depreciation rates to the average of Plant-in-Service as of May 2015 and 2016. 5 TR 319. The Company's initially filed projected accumulated depreciation provision for the test year incorporated depreciation expense calculated using book depreciation rates included in the Case No. U-16054 Settlement Agreement. 5 TR 319-320. The accumulated provision for depreciation for the projected test year, by functional group, utilizing the Case No. U-16054 rates was $4,628,728,000. Exhibit A-7, Schedule B3, line 22. Exhibit A-7 (NNB-44), Schedule B1,

[11] Mr. Coppola did not present a study or cost-benefit analysis to support his proposal to deny recovery of the investments in the AMI Program.

line 12, column C calculated a jurisdictional adjusted depreciation reserve amount of $4,614,934,000.

Staff witness Jay S. Gerken provided Staff's projected test year accumulated provision for depreciation in the non-jurisdictional amount of $4,628,244,000. 9 TR 1951-1952. Staff's jurisdictional projected test year accumulated provision for depreciation was provided in Exhibit S-2, Schedule B1 in the amount of $4,614,121,000. Exhibit S-2, Schedule B1, line 16, column (f). The $484,000 difference between the Company's initially filed projected test year accumulated provision for depreciation amount and the Staff's was the result of several adjustments by Staff to the Company's projected capital expenditures. 9 TR 1952.

On May 14, 2015, the Commission approved a Settlement Agreement in Case No. U-17653 that revises depreciation rates for electric and common utility plant. 5 TR 339. The Commission's Order in Case No. U-17653 indicated that, as provided by the Settlement Agreement, the new depreciation rates would become effective with the final order in Consumers Energy's next general electric rate case. 5 TR 339. Case No. U-17735 is Consumers Energy's next general electric rate case and therefore, the new depreciation rates will impact the projected accumulated depreciation provision for the test year. 5 TR 339-340. Using updated depreciation rates, Company witness Natalie N. Busack, Senior Rate Analyst, calculated the jurisdictional projected depreciation reserve amount of $4,632,583,000. Exhibit A-78 (NNB-68), line 12, column (c).

6. Construction Work in Progress ("CWIP")

Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart") witness Steve W. Chriss' proposal to remove construction work in progress from rate base (9 TR 1717-1719) should be rejected by the Commission. Mr. Chriss' recommendation ignores longstanding Commission

practice and the fact that the construction projects at issue will be completed within the period that rates are in effect.

Company witness Busack explained that the Commission has long allowed the utility to include CWIP in its rate base. 5 TR 349. Michigan Filing Requirements established in Case No. U-15895 (Final Order issued on December 23, 2008) included CWIP as part of the development of projected rate base (see Case No. U-15895 Final Order, attachment 2, Exhibit No. A-2, Schedule B1). 5 TR 349. Case No. U-15895 supplanted the filing requirements established in the Final Order of Case No. U-4771 dated May 10, 1976 which also included CWIP as part of the development of rate base (see Case No. U-4771 Final Order, attachment A, Exhibit A-2, Schedule B1). 5 TR 349. Based on these two filing requirements, the Commission has allowed CWIP to be included as part of rate base for almost 40 years. 5 TR 349.

Additionally, most construction projects included as CWIP are completed and closed within a year's time and therefore, will be put into operation within the period that rates are in effect. 5 TR 349. Alternatively, longer-term construction projects can be allowed to collect Allowance for Funds Used During Construction ("AFUDC") if they are greater than $50,000 and greater than six months of length of construction. 5 TR 349. Ms. Busack explained that the Commission recognizes that these longer-term projects may not be completed and operational over the test period and have remedied this by including an AFUDC offset in the calculation of net operating income. 5 TR 349. The return on rate base component of these longer-term projects which increases customers' cost will be offset by increased income from the AFUDC offset which will lower the customers' cost, with a net effect of $0 on the customer, theoretically. 5 TR 349. This AFUDC offset has also been part of the Commission filing requirements for almost 40 years. 5 TR 349.

As a result of the vast Commission precedent which supports including CWIP in rate base and the fact that these CWIP projects will be completed and operational within the period that the rates set by this proceeding are in effect, Mr. Chriss' recommendation should be rejected.

B. Working Capital

1. Working Capital Methodology and Calculation

Rate case Working Capital is developed using the balance sheet methodology. 5 TR 320. Use of the balance sheet methodology was mandated by the Commission in Case No. U-7350. 5 TR 320. Case No. U-1589 5 filing requirements also require this method be used to develop rate case Working Capital. 5 TR 320. The Company is requesting Working Capital be set at a jurisdictional amount of $759.386 million for purposes of determining rate base in this case.[12] See, Appendix B, line 9, column (d). The Company's projection is reasonable and consistent with the approach typically used in determining test year Working Capital using the Balance Sheet Method.

Company witness Busack testified that the Company, in its initial filing, developed its projected test year working capital requirement using the 2013 historical working capital as its starting point. 5 TR 320. This was first updated to reflect 13-month ended July 2014 actual balances and then the July average balances were adjusted to reflect: (1) changes to accounts receivable financing sponsored by Company witness Andrew J. Denato; and (2) changes in pension and Other Post Employment Benefit ("OPEB") balances sponsored by Company witness Herbert B. Kops. 5 TR 320. Details of the updates are shown on Exhibit A-7 (NNB-48), Schedule B4, pages 1 and 2.

[12] This amount includes the jurisdictional Working Capital amount of $661.342 million provided on Exhibit A-78 (NNB-68) as well as the impact of bonus depreciation and adjustments to account for the removal of certain Renewable Energy Accounts. 5 TR 341-343; Appendix B, footnote 4.

As discussed below, Staff's recommended non-jurisdictional Working Capital amount of $607,700,000 should be rejected by the Commission. 9 TR 1952. In calculating this amount, Staff performed incorrect adjustments related to bonus depreciation and cash equivalents and also failed to exclude certain renewable energy liability accounts.

2. Areas of Dispute with Staff's Working Capital Amount

The Company has three areas of disagreement with the Working Capital amount proposed by Staff in this case. First, Staff failed to make an appropriate adjustment in Working Capital to reflect the impact of a bonus depreciation extension for federal tax purposes in 2014. Second, Staff proposes to remove a significant amount of cash from the Company's Working Capital balance for the test year. Finally, Staff failed to make necessary adjustments related to certain renewable energy liability accounts. Staff's position should be rejected on all of these issues.

In December 2014, after the Company filed its testimony and exhibits in this case, Congress enacted an after-the-fact extension of its policy awarding tax payers bonus depreciation for new capital expenditures during calendar year 2014 after allowing the bonus depreciation provisions of the tax code to expire at the end of 2013. 5 TR 425. Staff witness Kirk D. Megginson proposed an adjustment to the Company's deferred federal income tax amount to reflect the impact of this change in law on the Company's capital structure. 10 TR 2108-2109. Consumers Energy agrees that Mr. Megginson's adjustment to deferred income taxes is appropriate; however, Staff failed to make a necessary corresponding adjustment to the Company's Working Capital amount to reflect the full impact of bonus depreciation. 5 TR 425. Company witness Denato testified that, in addition to the capital structure adjustments, the extension of bonus depreciation also results in an intercompany income tax receivable balance.

5 TR 426-427. Mr. Denato testified that this increases the Company's Working Capital balance and results in an increase in the Company's test year rate base of $121 million. 5 TR 427. This translates into a balance sheet impact of $78.1 million. See Appendix B, footnote 4.

Furthermore, it should be noted that just taking the increase in deferred taxes (a zero cost of capital component) without recognizing the offsetting increase in Working Capital has the effect of immediately reducing rates and providing a windfall tax benefit to customers. The immediate reduction of customer rates from accelerated tax depreciation and bonus depreciation would be considered to be a normalization violation of the Internal Revenue Code ("IRC"), which requires consistent treatment between the computation of tax expense for ratemaking purposes and the calculation of depreciation for ratemaking purposes. 26 USC 168(i)(9). The IRC specifies:

> "The procedures and adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (A)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other 2 such items and with respect to the rate base." *Id*.

The treatment proposed by Staff in this case is inconsistent treatment under the IRC, and hence, a normalization violation. A normalization violation would result in the loss of the utility's ability to claim accelerated depreciation and bonus depreciation for federal income tax purposes. 26 USC 168(f)(2). This would result in severe financial harm to both customers and the Company due to the loss of significant zero cost capital from these accelerated tax deductions. Therefore, it is critical that the corresponding accrued tax adjustment to the Company's projected Working Capital balance be included.

With respect to the cash balance included in the Company's test year Working Capital balance, Staff witness Gerken recommended that the Commission exclude more than $74 million temporary cash investments from the Company's cash balance in its calculation of Working Capital. 9 TR 1952. Company witness Denato offered rebuttal testimony in which he explained that Staff's proposal would leave the Company with just $7.8 million in its Working Capital balance for the test year. 5 TR 430. Mr. Denato testified that the level of cash proposed by the Company is needed to provide adequate liquidity during the test year and that the Company's proposed cash balance is in line with the average cash balances of other utilities. 5 TR 430-431. The Commission should reject Staff's proposed adjustment to the cash balance in the Company's Working Capital.

In addition to the above, Staff's calculation of the projected test year Working Capital was also deficient as Staff failed to make all necessary adjustments. 5 TR 342. Company witness Busack explained that it was discovered during Staff audit that there were four renewable energy liability accounts included the Working Capital that should have been allocated to investor supplied. 5 TR 342; Exhibit A-80 (NNB-70). It is necessary to exclude these accounts from Working Capital because the funds in these accounts are collected from customers via a separate charge which collects the costs associated with the Voluntary Green Generation program. 5 TR 341. Staff, however, did not make any adjustments to the Company's working capital amount to exclude these renewable liability accounts. 5 TR 342. The removal of these accounts causes the Company's projected test year working capital amount to increase by $19,932, 000 (Exhibit A-80 (NNB-70)) and results in a $2 million increase in the Staff's calculated revenue requirement. 5 TR 342. See, Appendix B, footnote 4.

C. Total Rate Base

Consumers Energy requests the Commission set rates using a jurisdictional total rate base for the projected test year of $9,247,692,000. The primary components (in thousands of dollars) are:

Total Utility Plant	$ 13,149,614
Less: Accum. Depreciation and Amortization	(4,632,583)
Net Utility Plant	$ 8,517,031
Less: Retainers & Customer Advances	(28,726)
Working Capital	759,386
Total Rate Base	$ 9,247,692

A more detailed calculation of rate base is shown in Appendix B to this Brief.

IV. RATE OF RETURN AND CAPITAL STRUCTURE

A. Introduction and Identification of Areas of Disagreement Between the Company and Staff

The rate of return for a regulated utility is based on the weighted average costs of the sources of capital comprising the capital structure. The weighted cost for each component of the capital structure is determined by multiplying the percentage ratio for that component by the cost rate for that component. The weighted cost rates for each component are then added to determine the overall rate of return.

Consumers Energy requests the Commission establish rates in this case using an after-tax overall rate of return of 6.38%, calculated as set forth on Exhibit A-87 (AJD-10). For the convenience of the Commission, the capital structure and rate of return summary from Exhibit A-87 are reproduced on Appendix E to this Brief.

Consumers Energy is requesting that the authorized return on equity be set at 10.70%. This is 40 basis points higher than the rate of return authorized by the Commission for Consumers Energy in the Company's most recent electric rate case, Case No. U-17087. 5 TR 239. For reasons set forth in the direct testimony and rebuttal testimony of Consumers Energy's

witness Dhenuvakonda Rao (see 5 TR 206-240, 242-276) and as discussed below, Consumers Energy requests the ALJ recommend and the Commission find that adopting Consumers Energy's proposed authorized return on equity of 10.70% in this case is reasonable given the risk profile for Consumers Energy's electric business, current conditions, and expectations regarding future increases in federal treasury rates.

In developing its recommended capital structure and cost rates, Staff reviewed the capital structure and cost rates proposed by Consumers Energy in its initial filing and recommended adjustments be made to the common equity balance, long-term debt cost, short-term debt cost, and the return on equity (see Exhibit S-4, Schedule D-1). Consumers Energy is adopting Staff's methodology for calculating the short-term debt cost rate, but notes that it should be recalculated to reflect the impacts of bonus depreciation. 5 TR 421. That recalculation results in a short-term debt cost rate of 1.73% as opposed to the 1.83% rate included in Staff's filing. Exhibit A-87. Consumers Energy does not agree with Staff's recommended reduction in the Company's common equity balance or its return on equity of 10.0%. Record evidence supports finding that a return of 10.0% would substantially understate the appropriate return on equity for Consumers Energy's electric business and would be unreasonable and unlawful. Furthermore Staff's proposed reduction in the Company's common equity balance should be rejected because it fails to take into account the Company's current need to attract capital, and the equity infusion planned for January 2016. 5 TR 421-423. Consumers Energy also disagrees with Staff's proposed long-term debt cost rate, which fails to account for recent interest rate trends on longer-term debt issuances.

The difference between the Company's calculated overall rate of return of 6.38% and the Staff's calculated overall rate of return of 6.04% is attributable to the disagreement concerning

the Company's debt and equity cost rates and the Company's common equity balance. Even though Staff accepted the Company's long- and short-term debt balances in their case, see 10 TR 2106; Exhibit S-4, Schedule D1, there is also a difference in the long- and short-term debt balances that result from correct treatment of the impacts of bonus depreciation. See Exhibit A-87 (AJD-10). Consumers Energy requests the Commission find that it is reasonable to adopt an authorized return on equity at 10.70%, as proposed by the Company, and the Company's other proposed cost rates and debt and equity balances as shown on Appendix E, rather than the capital structure and cost rates recommended by Staff.

B. Test Year Capital Structure

In the current case, Consumers Energy proposed that the rate of return should be calculated using a projected Consumers Energy capital structure for the 12-month period ending May 31, 2016. 5 TR 397, Exhibit A-9 (AJD-1), Schedule D1, columns (a) through (d); Exhibit A-87 (AJD-10), columns (a) through (c). Further, as shown on Exhibit A-87 and Exhibit S-4, Schedule D1, Company and Staff witnesses were in agreement as to the amounts outstanding that should be used in the capital structure for preferred stock, deferred federal income taxes, and the Job Development Investment Tax Credit ("JDITC"). The capital structure, as supported by Company witness Denato, is reproduced on columns (a) through (d) of Appendix E. Consumers Energy requests the Commission find this represents a reasonable and appropriate capital structure to use in this case and adopt this capital structure.

1. Capital Structure Component Balances

a. Common Equity Balance

In calculating the 13-month average common equity balance for the test year, Mr. Denato began with the common equity balance as of August 31, 2014, as shown on Exhibit A-9 (AJD-2), Schedule D1a, page 1, column (e-1) and then made adjustments as shown on column

(e-2). 5 TR 398. The common equity adjustment consisted of an adjustment to reflect retained earnings from September 2014 through May 2016 and an adjustment to reflect the average of equity infusions from September 2014 through May 2016. 5 TR 398. The calculations are shown on Exhibit A-9 (AJD-2), Schedule D1a, page 2. The resulting average common equity balance for the test year is $5.530 billion. Exhibit A-9 (AJD-2), Schedule D1, Schedule D1a, p. 1. Staff proposed two changes to the Company's common equity balance: (1) an increase in retained earnings; and (2) a proposal to ignore the Company's planned January 2016 equity infusion. Consumers Energy accepts Staff's first proposed change, but opposes Staff's proposal to reduce the Company's common equity balance should be rejected and is discussed further below.

b. Long-Term Debt Balance

In determining the test year long-term debt, Mr. Denato began with the August 31, 2014, long-term debt balance and adjusted the balance for projected debt retirements and issuances. 5 TR 400. Mr. Denato projected an average long-term debt balance for the test year of $5.050 billion. Exhibit A-9 (AJD-1), Schedule D1; Exhibit A-9 (AJD-2), Schedule D1a, page 1. The calculation is shown on Exhibit A-9 (AJD-2), Schedule D1a, page 3. This amount is the same as recommended by Staff. 10 TR 2106; Exhibit S-4, Schedule D1. In rebuttal, however, the Company adjusted the long-term debt balance to account for the effect of bonus depreciation. See Section III.B.2. of this Brief. The effect of bonus depreciation is to reduce the Company's long-term debt balance by $85 million. Exhibit A-93 (AJD-16), page 3. As a result, the corrected long-term debt balance for the test year ending May 2016 is $4.965 billion as shown on Exhibit A-87 (AJD-10), line 1, column (b).

c. Short-Term Debt Balance

Mr. Denato projected an average short-term debt balance for the test year of $194 million. This balance is shown on line 5 of Exhibit A-9 (AJD-1), Schedule D1, in column (b) and in column (f), line 5 of Exhibit A-9 (DVR-2), Schedule D1a, page 1. Mr. Denato stated that the average short-term debt balance is composed of two components: (1) the first is the average short-term debt – revolver/commercial paper balance of $75 million; and (2) the second is the average short-term debt – Renewable Liability balance of $119 million. 5 TR 401. The short-term debt balance recommended by Staff is the same as recommended by the Company. 10 TR 2106; Exhibit S-4, Schedule D1. However, as with long-term debt, the Company adjusted the short-term debt balance in rebuttal testimony to account for the effect of bonus depreciation. See Section III.B.2. of this Brief. The effect of bonus depreciation is to increase short-term debt by $23 million. Exhibit A-93 (AJD-16), page 3. As a result, the corrected short-term debt balance for the test year ending May 2016 is $217 million as shown on Exhibit A-87 (AJD-10), line 5, column (b).

d. Deferred Federal Income Tax Balance

Mr. Denato proposed an increase in the Company's deferred tax balance of $32 million over August 31, 2014 levels based on internal Company projections from the Company's Tax Department of book versus tax differences expected through May 2016. 5 TR 403. This resulted in a deferred tax balance for the test year of $2.346 billion. Exhibit A-9 (AJD-1), Schedule D1, line 6, column (b); Exhibit A-9 (AJD-2), Schedule D1a, line 6, column (f). Mr. Denato stated this method was used in response to requests by Staff and other parties in previous cases for the Company to use direct projections of deferred income taxes rather than projections based on proportion of historical capital structure for developing the Company's deferred income tax

balance. 5 TR 403-404. Due to the effects of bonus depreciation, Staff recommended using a deferred income tax balance of $2.528 billion. Exhibit S-4, Schedule D1. Consumers Energy agrees that, as a result of the extension of bonus depreciation by Congress, $2.528 billion of deferred federal income taxes represents the correct balance for use in the Company's test year capital structure. Exhibit A-87 (AJD 10), line 6, column (b).

e. Other Capital Structure Balances

The Company and Staff used balances for preferred stock and JDITC corresponding to balances in the historical period, with components for JDITC based upon the allocation of long-term debt, preferred stock, and common equity. 5 TR 404; 10 TR 2106; Exhibit A-87 (AJD-10); Exhibit S-4, Schedule D1.

2. Staff's and the Attorney General's Proposals to Adjust the Company's Common Equity Balance Should Be Rejected

Staff witness Megginson and Attorney General witness Coppola each argued that the Commission should adjust Consumers Energy's common equity balance downward in order to artificially adjust the Company's equity ratio below 52%. In order to achieve its adjustment, Staff proposed to increase the amount of retained earnings by applying the Company's methodology for calculating retained earnings to an updated estimate of net income for the test year. 10 TR 2109-2110[13]. Staff also proposed that the Commission not recognize the Company's planned $150 million equity infusion scheduled for January 2016. 10 TR 2110. The effect of these changes would be to reduce the Company's common equity ratio to 51.90% of permanent capital. Exhibit S-4, Schedule D1, line 3, column (c). Similarly, the Attorney General recommended that the Commission adjust the Company's common equity balance

[13] As noted above, Consumers Energy accepts Staff's proposed increase to the Company's retained earnings and the resulting impact on the Company's common equity balance, but opposes Staff's proposal to ignore the Company's planned January 2016 equity infusion.

downward by $168 million, while simultaneously adjusting the Company's long-term debt balance upward by $168 million. 10 TR 2328. The result is a common equity ratio of 50.5%.

Both Staff and the Attorney General explain their proposed modifications to the Company's common equity balance by citing Consumers Energy's goal of maintaining a capital structure of approximately 50% debt-50% equity. 10 TR 2110-2111, 2328-2329. Neither party offers any other reasons for their proposed reductions to the Company's common equity balance. And, even though neither party's adjustments to the common equity balance achieve a perfect 50/50 balance between debt and equity, neither party explains why their artificially created equity ratio is the right balance between debt and equity.

In rebuttal, Company witness Denato explains that the Company's goal of maintaining an equity ratio of approximately 50% is a general or "approximate" target, not a strict limit that should not be exceeded. 5 TR 421. Mr. Denato testified:

> "The actual equity ratio can (and has) fluctuated up or down by one to two percent. This is still in line with the Company's goal and a prudent level to support the Company's large capital investment program over the next several years. The Company's position regarding equity infusions has not changed since the filing of this case. The planned equity infusion is for the benefit and needs of Consumers Energy. The goals of the parent company include maintaining a strong, healthy utility, capable of serving the needs of its customers. This commitment is reflected in the equity infusion from the parent company to Consumers Energy in 2015 and continues with the planned equity infusion in January 2016." 5 TR 421-422.

Mr. Denato continued:

> "Second, there is good reason for the Company to have an equity ratio slightly higher than 50%. The Company is making significant capital investments over the next five years to maintain and improve utility infrastructure. The common equity balance and equity ratio projected for the test year in this case enables the Company to maintain strong credit ratings and better withstand any shocks in the financial markets, thereby ensuring a smooth

> implementation of its capital expenditure program. This also enables the Company to prefund its debt maturities to take advantage of low interest rates without jeopardizing the financial ratios. It should also be noted that certain credit rating agencies (e.g. Moody's) include securitization debt when calculating debt to equity ratios. Certain credit rating agencies (e.g. S&P) also consider items such as power purchase agreements, benefit obligations, and leases as 'debt' when calculating debt to equity ratios. Incorporating the projected equity infusion in January 2016 in the common equity balance enables the Company to maintain reasonable ratios after such adjustments.
>
> "Finally, the recommended common equity ratio in this case is not excessive when compared to the equity ratios of other utilities. As shown on Exhibit A-91 (AJD-14), the average equity ratio (as a percentage of permanent capital) for fiscal year 2013 was 52.73%. This is 65 basis points higher than the equity ratio recommended for Consumers Energy's capital structure in my direct testimony, and 25 basis points higher than my updated cost of capital on Exhibit A-87 (AJD-10) and Exhibit A-88 (AJD-11). In sum, the equity infusion planned for January 2016 is reasonable and a key component in the Company's plan to invest in its electric business infrastructure to better serve its customers." 5 TR 422-423.

So, while Staff and the Attorney General offer no reason to artificially adjust the Company's common equity balance, the Company explains that using the actual balances serve important goals beneficial to customers in this case. The Company's proposed common equity balance results in a common equity ratio that is in line with the Company's goal of approximately 50% common equity, while supporting the Company's intensive capital investment program and other financing goals.

Staff's and the Attorney General's arbitrary adjustments should be rejected. Including the $150 million equity infusion in the common equity balance results in a common equity balance for the test year of $5,523,860,308 as shown on Exhibit A-87 (AJD-10), line 3, column (b) and on Appendix E to this Brief.

C. Cost Rates

Consumers Energy and Staff witnesses agreed with respect to cost rates for preferred stock. As indicated previously, Consumers Energy and the Staff witnesses disagree with respect to cost rates for common equity, long-term debt, and short-term debt, although the Company has subsequently accepted Staff's short-term debt analysis provided that it is recalculated to reflect the impact of bonus depreciation.

1. Return on Common Equity

a. Introduction and Summary of Position – Reducing the Company's Proposed 10.70% Return on Equity As Proposed by the Staff and the Attorney General Would Send the Wrong Message to Investors and Analysts and Detrimentally Impact Both Consumers Energy and the State of Michigan

Consumers Energy's currently authorized return on equity for its electric business is 10.30%. This return was last set for Consumers Energy by the Commission in its May 15, 2013, Order in Case No. U-17087. In the current electric rate case, Consumers Energy's witness Rao presented multiple analyses and arguments supporting an increase in the return on equity to a rate of 10.70%. 5 TR 209. Mr. Rao's recommended 10.70% return is at the midpoint of his range of 10.50% to 10.90%. 5 TR 209. The 10.70% return on equity recommended for Consumers Energy is 40 basis points higher than the 10.30% return on equity which the Commission established for the Company in Case No. U-17087. 5 TR 239.

In the current electric case, Staff filed testimony in which it recommended the return on equity for Consumers Energy be set at 10.00%. The Attorney General's witness proposed a return of 9.75%, if the Commission uses Consumers Energy's projected capital structure, and ABATE's witness proposed a return of 9.60%. All of these recommendations significantly understate investor expectations and the appropriate return on equity for Consumers Energy's

electric business. These recommendations are less than the Company's presently authorized level of 10.30%, which has been in place since the Commission's June 7, 2012 Order in Case No. U-16794. In that case, the Commission concluded the return on equity should be set at a level higher than the return recommended by Staff or any of the intervenors, and above the high end of the Staff's range. It should do so again in the current case.

Adopting recommendations of the Staff, Attorney General, and Association of Business Advocating Tariff Equity ("ABATE") witnesses that the authorized return be reduced to 10.00% or below would send the message to investors that Michigan is a volatile regulatory environment in which investors cannot depend upon consistent or fair regulatory treatment. The recommendations of the Staff, Attorney General, and ABATE do not appropriately balance the needs of investors with the needs of customers and do not give due consideration to economic, financial, and public policy considerations with regard to: (1) maintaining the positive track record established by the Company and the Commission over the past several years with investors and rating agencies; (2) the scope of Consumers Energy's investment plans; (3) investor return on equity expectations; and (4) risk aversion and cost of equity. See 5 TR 209-211, 228-239.

Mr. Rao testified:

> "Based on my interactions with investors and rating agencies, I conclude that they view the authorized ROE as a key signal provided by a utility commission and that the authorized ROE will affect their perception of the Michigan regulatory environment, investment in Consumers Energy, and investment in Michigan. While investors view Michigan's regulatory environment as constructive, they are counting on continued stability in its regulatory decisions. If investors and credit rating agencies were to perceive the regulatory environment as deteriorating, this would quickly undercut the positive view that they currently hold. The current equity return of 10.30% is at the low end of what I believe investors view as reasonable for Consumers Energy's electric

> business. I believe that an authorized ROE of 10.70% is reasonable given the risk profile for the Company." 5 TR 249-250.

Mr. Rao further testified:

> "Staff's recommendation of 10.00%, less than the presently authorized level of 10.30%, would send a wrong signal to the investor community at a time Consumers Energy is implementing a large infrastructure improvement program and put the Company at a disadvantage in raising capital from the investor community. Lowering the authorized ROE would negatively impact the value of their investment in the Company and jeopardize the progress that the Company and the State of Michigan have made during the last several years in promoting Michigan as a place to invest. Once lost, it will be difficult to regain investors' confidence." 5 TR 243.

Mr. Rao provided both qualitative and quantitative support for his conclusion that the cost of common equity should be set at 10.70%, rather than at a level of 10.0% or less as proposed by the witnesses for Staff, the Attorney General, and ABATE. Consumers Energy requests the Commission set the authorized return on equity at 10.70% in this case.

b. Applicable Principles

It is well established that equity investors in a public utility, such as Consumers Energy, are entitled to a return on equity investment commensurate with investments of comparable risk, that earnings must be sufficient to assure financial soundness of a utility, and a utility must be able to earn a return that will allow it to maintain its credit and raise required capital. *Bluefield Water Works and Improvement Co v Public Service Commission of West Virginia*, 262 US 679, 693; 43 S Ct 675; 67 L Ed 1176 (1923), *Federal Power Commission v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court stated in *Bluefield*:

> "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public *equal to that generally being made at the same time* and *in the same general part of the country on investments in other business undertakings which are attended by*

> *corresponding risks and uncertainties*. . ." 262 US at 692. (Emphasis added.)

Similarly, the Supreme Court stated in *Federal Power Commission v Hope Natural Gas*:

> "By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital." 320 US at 603.

Rates which are not sufficient to yield a reasonable return on utility property at the time it is being used are unjust, unreasonable, and confiscatory. *Bluefield Water Works*, *supra*, 262 US at 690.

When the common stock of a public utility is not publicly traded, as with Consumers Energy, indirect or proxy approaches must be used to calculate an appropriate return on common equity. 5 TR 214. Since no one method perfectly simulates the operation of the market, multiple models combined with an assessment of the marketplace are typically used in evaluating the market required cost rate for common equity. 5 TR 213-214.

c. Proxy Group Selection Criteria

Under principles set forth in the *Hope* and *Bluefield* decisions, it is necessary to determine a return that will reflect the investor-perceived risk of the utility being examined as compared with alternative investments and compensate investors for that risk. For his analyses, Mr. Rao selected a proxy group of publicly traded electric companies that met the following criteria: they had to (1) be classified as electric utility companies by the Value Line Investment Survey ("Value Line"); (2) be paying current common stock dividends; (3) have bonds rated at or above a minimum investment grade of Baa3 by Moody's Investor Services ("Moody's") and BBB- by Standard & Poor's ("S&P"); (4) have 45% or more of its operating revenues from

regulated electric operations; (5) have net plant greater than $5 billion; and (6) not be a company that was planning to merge with another company. 5 TR 214-215. The application of these screening criteria resulted in a group of 23 companies. 5 TR 215.

Mr. Rao also identified a smaller proxy group of companies whose net plant is comparable to Consumers Energy's (i.e. less than $10 billion). 5 TR 215. Mr. Rao testified that academic literature has shown a correlation between company size and returns on equity. 5 TR 215. Mr. Rao stated that many of the companies included in the full proxy group are significantly larger than Consumers Energy, and as a result, the averages from the entire proxy group may underestimate the appropriate return on equity for Consumers Energy. 5 TR 215. However, Mr. Rao testified that limiting his analysis to only the similar sized companies would have resulted in a proxy group of only six companies, which Mr. Rao concluded was insufficient for many of the traditional analyses. 5 TR 215. However, where the use of the smaller proxy group provides additional insight, Mr. Rao showed the results in some of his quantitative models. 5 TR 215. The list of the proxy group companies is shown on Exhibit A-9 (DVR-1), Schedule D5, page 1 and page 3 (where proxy group companies with net plant less than $10 billion are marked with an asterisk).

d. <u>Analytical Methodologies and Conclusions</u>

Mr. Rao assessed the return on equity for Consumers Energy's electric operations using multiple methodologies in combination with assessments of the market and risk environment for Consumers Energy. Among other things, Mr. Rao: (1) studied the current outlook of the national economy and capital markets; (2) analyzed the investor perceptions of the Michigan regulatory environment and risk factors associated with investment in Consumers Energy; and (3) performed standard quantitative analyses to determine the cost of equity of a proxy group of

companies and compared the risk-return profile of Consumers Energy with other similar investments, and (4) considered current trends in the business climate for electric utilities and Consumers Energy in particular. 5 TR 214-239.

As part of his assessment, Mr. Rao undertook analyses using the Capital Asset Pricing Model ("CAPM") and Empirical Capital Asset Pricing Model ("ECAPM"), a Risk Premium analysis, the Discounted Cash Flow ("DCF") model, and a Comparable Earnings Analysis. These analyses are described at 5 TR 216-227. Several of the analyses performed by Mr. Rao calculate expected return on equity as some level of premium above a risk-free rate. Traditionally, the risk-free rate used to perform these analyses is a projection of yields on U.S. Treasury Bonds. However, Mr. Rao testified that, as a result of unprecedented government intervention into monetary policy following the economic crisis in 2008, U.S. Treasury rates are artificially low – 1-2% below historical levels – and are skewing traditional cost of capital analyses downward. 5 TR 231-232. Mr. Rao notes in his testimony that utility stocks are particularly sensitive to interest rates and utilizing projected interest rates which have considerable variability would underestimate the Company's required return on equity. 5 TR 219. To mitigate the impacts of these temporary economic conditions and uncertainty, Mr. Rao used a risk-free rate based on the average income return of Long-Term Government bonds from 1926-2013 as published by Morningstar in his CAPM, ECAPM, and Risk Premium analyses. 5 TR 218, 222, 228.

Staff acknowledges that it is inappropriate to include data from periods of time in which there are "non-market based administered interest rates that were not tied to market forces" in performing cost of capital analyses. 10 TR 2117. But, Staff, the Attorney General, and ABATE nevertheless each perform CAPM and Risk Premium analyses using projections of yields on

U.S. Treasury Bonds reflecting the current non-market based administered interest rates. 10 TR 2117, 2171, 2333. These treasury rates are not tied to market forces, as Mr. Rao points out in his testimony. 5 TR 228-234. Because each of these parties fails to adjust for artificially low treasury rates in their respective analyses, they understate the Company's required return on equity, and their analyses should be rejected.

Using the appropriate analyses recommended by Mr. Rao, the proxy group returns shown on Exhibit A-9 (DVR-1), Schedule D5, page 14, are as follows:

Proxy Group/Utility Results	Average	Median
Capital Asset Pricing Model w/ Historical Risk-Free Rate	10.13%	10.31%
Empirical Capital Asset Pricing Model w/ Historical Risk-Free Rate	10.55%	10.69%
Risk Premium Analysis Over Utility Bonds	10.65%	10.56%
Discounted Cash Flow Model	8.94%	9.00%
Comparable Earnings Analysis	10.06%	9.77%
Recommended Cost of Equity Range for Consumers Energy	10.50% - 10.90%	
Recommended Ratemaking Cost of Equity for Consumers Energy:	10.70%	

In evaluating these results, it is appropriate to take into consideration the results of standard quantitative models do not fully reflect the returns that investors expect given current economic and financial conditions. 5 TR 214. Mr. Rao explained:

> "The models are based on the assumption that economic conditions are relatively stable and that current market inputs are reflective of their long-term outlook. That assumption is not currently being met. Markets are volatile and there is significant uncertainty, mainly because of the unprecedented amount of intervention by central banks during the last several years. For example, in September and October of 2014 the Standard & Poor's ('S&P') 500 Index dropped nearly 150 points with interest rates fluctuating nearly 25 bps in one day (compared to typical intraday movements of 4 to 8 bps). As a result, the models tend to understate the return that investors currently require to compensate them for risk." 5 TR 214.

Despite Mr. Rao's efforts, discussed above, to adjust his analytical methodology to account for some aspects of these circumstances, the models did not fully address this issue.

Mr. Rao testified:

> "As the Commission has recognized in prior cases, establishing an appropriate ROE is not subject to mathematical calculation with scientific exactitude, but depends on an examination of all factors involved and the exercise of professional judgment." 5 TR 264-265.

Consumers Energy submits that the evidence, on the whole record, supports a conclusion that an authorized return on equity of 10.70% will reasonably balance customer and investor interests.

e. Additional Risk Considerations

The cost of capital is an opportunity cost. Mr. Rao testified that the basic principle in setting a fair rate of return is the risk-return parity. 5 TR 212. Mr. Rao described this as the idea that the investment community determines the market price of financial securities such that the anticipated returns compensate the investor for the overall perceived risk of the specific security. 5 TR 212-213. In recommending an appropriate level for the Company's return on equity in this case, Mr. Rao also considered the following factors affecting the risk-return analysis:

(i) Economic Outlook, Interest Rates, and Risk Aversion

Mr. Rao testified that the U.S. economy has gained traction since the 2008-2009 crisis, but that the economy remains fragile. 5 TR 228. These circumstances add to investors' risk perceptions. 5 TR 228. Mr. Rao pointed to the Federal Reserve's recent decision to discontinue its quantitative easing program and actions by central banks in Europe and Japan to expand monetary supply as important contributors to current economic uncertainty and volatility. 5 TR 229. Mr. Rao testified:

> "Greater volatility, or large swings up or down in value in the financial markets increases overall investor risk. During times of extreme fluctuations in investments, there is greater uncertainty and risk among the investment community. As the relative amount of risk in an investment increases, an investor will require a higher return on that investment to compensate for the risk level. The volatility in the financial markets should be taken into consideration in developing the appropriate ROE for the Company. In 2014, there was a great amount of volatility in the U.S. financial markets. In October 2014, after the announcement of weak economic data, the S&P 500 Index dropped nearly 150 points. The Chicago Board Options Exchange Volatility Index, a popular measure of the volatility of S&P 500 Index options, jumped from a five-year low of 10.28 in early July to over 30 on October 15, 2014. This rapid change in volatility and investor sentiment is another reason I have focused my analyses towards longer term averages for market observables." 5 TR 229-230.

Mr. Rao also testified regarding his analysis of how interest rates will move going forward. He testified that interest rates have little room for further decline without risking potential deflation. 5 TR 232. Mr. Rao stated that the combination of a recovering U.S. economy with the end of the Federal Reserve's asset purchase program will put upward pressure on interest rates. 5 TR 232. Mr. Rao sponsored Exhibit A-9 (DVR-1), Schedule D5, page 13, which is a "heat map" based on survey data from Bloomberg demonstrating that there is a "relative consensus" of investors' expectations that there will be near-term interest rate increases. 5 TR 233.

Mr. Rao testified that, from an investor standpoint, U.S. Treasuries and utility stocks are similar competing investment alternatives. 5 TR 232. He testified:

> "Both securities offer a relatively lower-risk profile and a stable return compared to other investment options. As treasury yields rise from their historically low levels, U.S. Treasuries will become more attractive to investors relative to utility stocks. This shift causes the required return on utility equity to push higher. This phenomenon has already occurred in 2013. As shown in the chart on page 10 of Exhibit A-9 (DVR-1), Schedule D5, starting in April 2013, the ten-year U.S. Treasury has made a steep climb to 3% at the end of 2013. However, the Philadelphia Stock Exchange Utility Sector Index, a stock index composed of public utility

> stocks, during the same time period, shows a general downward trend. Also, through 2013, the Utility Sector Index, which was up 7%, has underperformed versus the stock market as a whole, as measured by the S&P 500 Index, which was up 30% for the same time period." 5 TR 232-233.

Mr. Rao testified that the analyses included in the testimony of Staff, the Attorney General, and ABATE fail to appropriately account for this volatility or the likelihood of rising interest rates. 5 TR 245, 264, 273. Mr. Rao points out that both 10- and 30-year treasury rates increased significantly after Staff and the intervenors filed their testimony in this case. 5 TR 252. Mr. Rao testified:

> "Analysts agree that when interest rates begin to rise, they increase quickly and in an unpredictable manner. Interest rate forecasts have also been very volatile in the last few months, creating additional risk to investors." 5 TR 253.

As a result, Mr. Rao concludes that Staff's, the Attorney General's, and ABATE's return on equity recommendations, which relied on a set of interest rate projections on a given date, do not appropriately consider this risk. 5 TR 253.

(ii) Investor Return on Equity Expectations

The authorized ROE is one of the most important parameters used by analysts to determine the attractiveness of investing in utilities. 5 TR 210. Mr. Rao testified that investors generally view the present overall regulatory environment as supportive. 5 TR 234. However, he emphasized that investors look for continued confirmation that the Commission understands the investment community and the importance of returns in attracting capital to Michigan. 5 TR 234. In his testimony, Mr. Rao quotes a number of investment sources that confirm the current positive perception of the Michigan regulatory environment. 5 TR 234-235, 246-247. He also notes that Michigan's constructive regulatory environment is "built into investors' expectations and that a regression from the current status would be viewed negatively." 5 TR 235. ABATE's

witness Christopher C. Walters reviewed in his testimony many of the same sources of investor and market information analyzed by Mr. Rao, and acknowledged the investment community's recognition of the generally positive regulatory environment in Michigan. 10 TR 2158-2166. But, Mr. Walters appears to assume that these opinions would somehow necessitate a lower authorized return on equity in this case. 5 TR 267. However, Mr. Rao testified, "It does not follow that because investors view the regulatory climate as constructive with an authorized return of 10.30%, this supports a reduction in the authorized return below 10.30%." Mr. Walters' conclusion is a non sequitur. If adopted, it would result in undoing the very constructive regulatory environment that has facilitated Consumers Energy's successful capital attraction activities over the past several years and garnered such positive reviews by the investment community.

Mr. Rao stated that setting the rate of return at 10.00% or lower, as recommended by Staff, the Attorney General, and ABATE, would send a significant negative message to investors that would undercut the progress that has been made in improving investor perceptions of Michigan in general and the Michigan regulatory environment in particular. 5 TR 243. Any authorized return lower than the Company's current authorized rate of 10.30%, as Staff, the Attorney General, and ABATE have proposed, would not be reasonable. 5 TR 251. In contrast, a return of 10.70% is within the range of reasonable returns, and adopting a 10.70% return in this case will help assure that Consumers Energy continues to have reasonable access to capital on reasonable terms and conditions. 5 TR 251-252.

Consumers Energy presented evidence that, over the next five years, the Company plans to continue making significant capital expenditures, totaling nearly $5.0 billion, in its electric operations to maintain and improve utility infrastructure, increase the amount of energy

generated from renewable resources, and ensure that the Company's customers receive the quality of service that they expect. 5 TR 250. Mr. Rao testified that, during this period, it is imperative that the Company maintain a supportive return on equity. 5 TR 250-251. Reducing the return on equity as proposed by the Staff, the Attorney General, and ABATE could lead to increases in cost of capital or limit access to capital. Neither would be in the best interest of customers. 5 TR 251.

f. Additional Responses to Staff and Intervenors

In addition to the issues discussed above, witnesses for Staff and intervenors express criticism of a few other aspects of the Company's return on equity analysis. First, witnesses for Staff and ABATE criticize the Company's use of an ECAPM analysis. In response, Mr. Rao explains that these criticisms are unfounded. Mr. Rao testified that the ECAPM analysis is a theoretically sound response to well-known shortcomings in the traditional CAPM analysis, is used by some regulatory witnesses and decision makers, and is well supported by a leading industry expert. 5 TR 259-260, 271. In rebuttal, Mr. Rao noted. "In addition, findings from a February 2013 report from the Brattle Group entitled 'Estimation the Cost of Equity for Regulated Companies' (pages 15-20 reinforces my opinion of the many weaknesses in the CAPM model as well as the use of the ECAPM to correct for these deficiencies." 5 TR 260. Staff's and ABATE's criticisms of the ECAPM should be rejected.

Second, the Attorney General and ABATE criticize the Company's Comparable Earnings Analysis. Again, however, Mr. Rao explains that their criticism is unfounded. Mr. Rao explained in rebuttal that the Comparable Earnings Analysis uses the ratio of earnings per share to projected book value of the proxy group companies as a reasonable proxy of analyst and investor expectations for regulated utility returns. 5 TR 272. Mr. Rao points out that the

Comparable Earnings Analysis uses Value Line projections, which are used by all parties in the case who perform DCF analyses, as the source of its calculations. 5 TR 272, 274.

Finally, a number of parties argue that, to the extent the Commission grants the Company's request for certain ratemaking mechanisms in this case, it should implement a corresponding reduction in the Company's final authorized return on equity. Mr. Rao offered the following testimony responding collectively to several parties' arguments:

> "As I discussed earlier in my rebuttal, tracker mechanisms similar to those proposed in this case are prevalent among many other utilities, as well as the Company's proxy group. These mechanisms are commonly-used tools established to provide efficient regulation and assist utilities in earning their authorized regulatory returns. Further, I refer back to my earlier testimony in rebuttal to Staff witness Megginson where I discuss a report from the Brattle Group finding that utilities with a decoupling mechanism did not have a lower cost of capital than utilities without such a mechanism. The report found that 'judgments where commissions reduced allowed rates of return because of decoupling, we found that the estimated cost of capital for decoupled utilities was higher by a small but statistically significant amount.' Each of these three witness' recommendations that the approval of either or both of the Company's proposed recovery mechanisms necessitate a potential downward adjustment to the Company's authorized ROE should be rejected." 5 TR 276.

Mr. Rao sponsored the Brattle Group report as Exhibit A-117 (DVR-2) in this case. Page 2 of the report confirms Mr. Rao's assessment. It states:

> "The findings of our analysis do not support the belief that utilities with decoupling have a lower cost of capital than utilities without decoupling. Contrary to what some might expect to find, at least on the basis of the opinions of certain intervenors and the (minority set of) judgments where commissions reduced allowed rates of return because of decoupling, we found that the estimated cost of capital for decoupled utilities was higher by a small but statistically significant amount." Exhibit A-117 (DVR-2).

Contrary to the requests of Staff and various intervenors, it would be inappropriate to reduce the Company's return on equity corresponding to approval of either the IRM or the Revenue Adjustment Mechanism proposed by the Company in this case. None of the parties' additional criticisms or arguments opposing the Company's cost of common equity analysis have merit. The Commission should reject these arguments.

g. Return on Equity Conclusion and Request for Relief

For reasons addressed above and in the evidentiary presentation of Consumers Energy's witness Rao, Consumers Energy requests the authorized return on equity be set at 10.70% rather than decreased from its current level of 10.30% to 10.00% or below as proposed by the Staff, the Attorney General, and ABATE. If the return is set lower than the Company's recommended level of 10.7%, then it should at least be set no lower than the currently authorized level of 10.30%. A reduction below 10.30% would be particularly unreasonable given current economic and financial conditions, the uncertainty and volatility in the capital markets as a result of activity by the Federal Reserve, and the need for Consumers Energy to raise substantial amounts of funding for planned investments in Michigan.

Authorizing a return on equity in this case of 10.70% for Consumers Energy in combination with the capital structure and cost rates for other components as proposed by Consumers Energy results in an overall after-tax rate of return of 6.38% as compared to the 6.04% overall rate of return calculated by Staff using a 10.0% return. The calculation of the 6.38% overall rate of return is shown on Appendix E.

2. Long-Term Debt Cost

The Company originally proposed a long-term debt cost rate of 5.05% in this case based, in part, on the Company's projected 6.00% interest rate on an expected $300 million new debt issuance in July 2015. 5 TR 406; Exhibit A-9 (AJD-4), Schedule D2; Exhibit A-9 (AJD-1),

Schedule D1, line 1, column (e). Staff projected a lower rate of 3.60% for the Company's July 2015 new debt issuance based on published forecasts for 10-year Treasury Bond rates. 10 TR 2106-2107. Consumers Energy agrees that updated data supports a lower interest rate for the July 2015 new debt issuance than the 6.00% originally proposed by the Company. However, in rebuttal, Consumers Energy's witness Denato testified that U.S. Treasury Bond rates have trended up since Staff filed its testimony in this case, and he points out that the Company is considering a debt issuance with a longer term than assumed by Staff. 5 TR 424. Consequently, the Company contends that the interest rate assumed for the July 2015 new debt issuance should be more in line with current expectations for 30-year Treasury Bonds. 5 TR 424. Mr. Denato testified that an interest rate of 5.00% more appropriately reflects the likely rate for the July 2015 new debt issuance. 5 TR 424. Recalculating the Company's proposed long-term debt cost based on a 5.00% new debt issuance in July 2015 and the adjustments in the Company's long-term debt balance due to the extension of bonus depreciation discussed above results in a new long-term debt cost rate of 5.02% as shown on Exhibit A-87 (AJD-10), line 1, column (e). The Commission should adopt that rate in this case.

3. Short-Term Debt Cost

The Company calculated its short-term debt cost rate by applying a projected London Interbank Offered Rate ("LIBOR") rate to the Company's forecast of its outstanding average short-term borrowing under its commercial paper facility. Exhibit A-9 (AJD-5), Schedule D3, page 2. Staff proposed that the short-term debt cost rate should instead be calculated based on the Company's commercial paper rate applied to the Company's forecast of average short-term borrowing. 10 TR 2108. Staff also applied the Company's commercial paper rate to the Company's test year Renewables Liability balance. 10 TR 2108. Staff's calculation results in a short-term debt cost rate of 1.83%. 10 TR 2107; Exhibit S-4, Schedule D-1. Consumers Energy

accepted Staff's alternative methodology for calculating the short-term debt cost rate, but noted that it should be recalculated to reflect the updated short-term debt balance resulting from the adjustments required as a result of bonus depreciation. 5 TR 421. This results in a short-term debt cost rate of 1.73%. Exhibit A-87 (AJD-10), line 5, column (e); see also Appendix E.

4. Other Cost Rates

The Company and Staff are in agreement that the cost rate for preferred stock should be 4.50% (*see* Exhibit A-9, Schedule D1), the cost rates for the long-term debt, preferred stock, and common equity components of JDITC should correspond to the cost rates established for long-term debt, preferred stock, and common equity, and the cost rates for other components should be zero. Exhibit A-87, Exhibit S-4, Schedule D1.

D. Overall Rate of Return

Using a return on equity of 10.70% in the capital structure, in combination with the cost rates for the other components recommended by the Company at the conclusion of its rebuttal testimony, results in an after-tax cost of capital of 6.38% and a pre-tax weighted cost of capital of 9.22%. The capital structure, cost rates, and calculation of these returns are shown on Exhibit A-87 (AJD-10), and reproduced in Appendix E. Consumers Energy requests the Commission adopt the capital structure and cost rates as shown on Appendix E to this Brief.

V. ADJUSTED NET OPERATING INCOME

A. Jurisdictional Revenues and Sales Forecast

1. Sales Forecast

Company witness Hubert W. Miller III presented the Company's projected jurisdictional electric sales revenues for the test year ending May 31, 2016. Mr. Miller testified that the Company has projected its jurisdictional electric sales for the test year to be 37,729 GWh. Exhibit A-10 (HWM-3), Schedule E-3. This projection was developed by employing the

detailed analytical methodology described in Mr. Miller's testimony. 6 TR 768-774. Full service and Retail Open Access ("ROA") customers are represented in the forecast.

The key variables affecting the Company's forecasts are weather, the economy, and demographics. 6 TR 767. The 15-year average of Heating Degree Days and Cooling Degree Days are used to capture the seasonal variation of weather in deliveries and demand across the year. 6 TR 767. To predict the long-term customer forecast, IHS Global Insight's ("Global Insight") population projections are used. 6 TR 767. As an indicator to capture the economy's growth expectations, the Company's uses Global Insight's employment and industrial production forecasts. 6 TR 767.

The Company's total generation requirements were projected using the Commission's past methodology. Mr. Miller testified that "[c]onsistent with prior filings, the forecasted total electric deliveries are increased by a line loss factor of 7.2 percent to determine the Company's total generation requirements . . . ." 6 TR 773. This can be seen in the system output identified in Exhibit A-10 (HWM-3), Schedule E-3 and Exhibit A-10 (HWM-4), Schedule E-4.

Additionally, the Company's forecast reflects energy efficiency savings. As a result of the Company's energy efficiency programs, savings related to energy efficiency are predicted to continue growing at 1% per year through the forecast period. 6 TR 772.

The Company's electric deliveries are expected to increase by 1.1% per year from 2013 to the projected test year. 6 TR 771. The rate category level results are shown in Exhibit A-10 (HWM-2), Schedule E-2. The annual class level results for 2004-2019 are shown in Exhibit A-10 (HWM-3), Schedule E-3.

a. Response to the Attorney General

The Attorney General witness Coppola argues for the use of an updated sales forecast. Exhibit AG-1 is an updated forecast that shows electricity sales for the projected test year are expected to reach 38,095 GWh. 10 TR 2270-2271. This updated forecast was provided to the Attorney General in discovery (10 TR 2270), and as Mr. Coppola indicated, "[t]his updated information reflects, to a large degree, the continued economic expansion in the Company's service area and continued growth in electric load." 10 TR 2271. Based on this updated forecast, Mr. Coppola maintained that the Company's forecasted revenue and operating income for the projected test year are inaccurate because sales for the projected period are understated. 10 TR 2272.

Mr. Miller testified that the use of the Attorney General's proposed sale forecast is unreasonable. He explained that the Company prepares two electric deliveries forecasts a year – one in April and one in October. 6 TR 778. The "updated" forecast that the Attorney General relied upon was prepared in October of 2014. Since that time, the Company completed its April 2015 forecast, which projects 37,813 GWh of electric deliveries for the 2015-2016 test year. 6 TR 778. If the Commission agrees with the Attorney General that the most recent forecast should be utilized, the April 2015 sales forecast should be adopted.

The difference in the October 2014 and April 2015 forecasts is an update in deliveries and economic data. 6 TR 778. Global Insights reduced its projection for the amount of economic activity during the projected test year. Mr. Miller testified that Global Insights "revised down their forecast in April 2015 based on slower first quarter 2015 growth." 6 TR 778. Exhibit A-109 (HWM-6) provides a comparison of the change in economic variables used by Global Insights in the October 2014 and April 2015 forecasts. The impact of utilizing an

updated electric deliveries forecast in this case would result in an increase in operating revenues of $348,000. See Exhibit A-110 (HWM-7).

Based on the *de minimus* impact, the Company recommends the use of its originally filed sales forecast. However, if the Commission elects to utilize an updated forecast, the Commission should adopt the April 2015 forecast as it is based on the most recent information available. If the April 2015 forecast is utilized, a more detailed revenue analysis will need to be done for rate design and cost-of-service purposes. 6 TR 778.

b. Response to MEC/NRDC/CARE

MEC/NRDC/CARE witness Douglas B. Jester argued against the use of the Company's generation requirements forecast. This recommendation is based on Mr. Miller's use of a loss factor of 7.2% in forecasted total electric deliveries to determine the Company's total generation requirements. 10 TR 2362. Mr. Jester asserted that the Company's generation forecast is inappropriate because it does not reflect changes in system losses due to changes in the composition of the class loads. 6 TR 779. These arguments fail to recognize how the Commission has previously utilized the loss factor for the generation requirements forecast and ignore the fact that a weighted system loss factor has minimal impact on the forecast.

Since approximately 2007, the Company's generation forecast has utilized a line loss factor of 7.2%. This factor was developed by the Company's Accounting Department and is based on the three-year average system efficiency for the period ending April 2007. 6 TR 789. The forecast used in this case is based on the approach utilized by the Commission in the Company's last general electric rate case, MPSC Case No. U-17087, and PSCR Plan case, MPSC Case No. U-17095, to establish rates. 6 TR 770. Nevertheless, the Company agrees that

if the Commission approves a new line loss factor in this case, then the updated loss factor should be used in determining its generation requirements forecast going forward. 6 TR 779.

Moreover, the Company's generation forecast appropriately uses a system average cumulative loss factor. 6 TR 779-780. While Mr. Miller agreed that the Company expects industrial class deliveries to increase slightly over the next five years, this does not render the use of the loss factor to determine generation requirements inappropriate, and a weighted system loss factor would not significantly alter the results of the forecast. 6 TR 779-780. Mr. Miller provided an example of the impact. He explained:

> "For example, if the hypothetical loss factors for the residential, commercial, and industrial classes are 7.75 percent, 7.25 percent, and 6.75 percent, respectively, then the weighted system loss factor for the 2015/2016 test year and 2019 would be 7.23 percent and 7.22 percent. The small difference in the weighted system load factor from changes in the composition of class load, 0.01 percent decrease in this example, is not enough to warrant rejecting the Company's generation requirements forecast in this case." 6 TR 780.

Exhibit A-111 (HWM-8) demonstrates that impact a weighted system loss factor on changes in class composition. As the differences between the use of a system average cumulative loss factor and a weighted system loss factor are minimal, the Commission should reject the arguments of Mr. Jester and adopt the Company's generation forecast for this proceeding.

2. <u>Total Electric Operating Revenues</u>

Mr. Miller also presented the Company's analysis of projected test year total electric operating revenues, which includes Base Tariff Revenues, PSCR Revenues, and Miscellaneous Revenues. Mr. Miller testified that the Company has projected its total electric operating revenue for the projected test year to be $4.219 billion. Exhibit A-10 (HWM-1), Schedule E-1. This amount was adjusted to $ 4.220 billion after including the revenue from various job work activities that are not reported as electric operating revenues. The jurisdictional portion of the

forecasted test year present revenue, including job work revenue, is $4,196,124,000. This translates to a test year jurisdictional total revenue amount of $4.204 billion after accounting for jobwork expense. See Appendix C, page 1, line 1, column (d).

The Company developed its present revenue calculation by making adjustments to 2013 actual sales and revenues. Exhibit A-10 (HWM-1), Schedule E-1 summarizes the component differences between the 2013 historic revenues and the forecasted test year revenues. Mr. Miller discussed the adjustments made to 2010 historical actual sales and revenues for the purpose of developing the projected test year sales and revenues. 6 TR 766-774.

Included in the projected test year present revenue is the impact of the termination of Rate E-1. The Rate E-1 tariff is scheduled to terminate at the end of November 2015. The projected revenues utilized the collection of revenues under Rate E-1 from June 2015 through November 2015 and demand-based rate design, Rate GPD, from December 2015 through May 2016. 6 TR 766. This increases revenues by $12 million. 6 TR 767.

Additionally, the Company projected present revenues proposal includes auto-enrolling residential customers who are 65 years or older in its Senior Citizen provision. 6 TR 766-767. Mr. Miller testified that there are approximately 240,000 residential customers who satisfy the age criteria but are not presently enrolled in the Senior Citizen provision, and transferring these customers is expected to reduce revenues by approximately $10.2 million. 6 TR 766.

Staff accepted the Company's Miscellaneous Revenues (9 TR 1778), and agreed with the Company auto-enrolling customers into the Senior Citizen provision as long as no seniors who are currently enrolled in the Residential Income Assistance Program are switched to the Senior Citizen provision. 9 TR 1778-1779. However, Staff proposed adjusting the Company's projected revenues to reflect the number of customers who are eligible to receive service under

the Residential Income Assistance ("RIA") provision. 9 TR 1819. In support of this adjustment, Staff witness Daniel J. Gottschalk argued that the Company's projected number of monthly RIA customers is not supported by historical data. 9 TR 1777. Thus, Mr. Gottschalk requested that the number of income assistance customers forecasted to participate in the RIA be reduced. This would increase the Company's present revenues by $1,259,034. 9 TR 1776.

Mr. Miller testified that reducing the number of customers in the RIA provision is unwarranted. While the Company agrees that the level of customers participating in the RIA has recently decreased, Mr. Miller testified that the Company has been investigating the cause of this decrease since January 2015. 6 TR 777. The Company has identified approximately 10,000 customers in its Consumers Affordable Resource for Energy Program who are also eligible for the RIA provision. Mr. Miller stated that these customers will be auto-enrolled in June 2015. 6 TR 777. The Company further projects approximately 7,000 additional Consumers Affordable Resource for Energy customers would be enrolled in 2016. 6 TR 777. Therefore, the Company's proposed number of customers enrolled in the RIA provision should remain unchanged, and the Company's projected amount of electric operating revenues for the test year should be adopted.

B. Fuel, Purchased, and Interchange Expense

Company witness Ronk testified concerning the Company's projected fuel, purchased, and interchange power expense. See 8 TR 1497-1498; Exhibit A-59. Mr. Ronk explained that these power expenses were projected using production cost simulations. 8 TR 1497. Specifically, the PROMOD IV program developed by ABB (formerly Ventyx) was used to prepare these simulations. 8 TR 1498. This program "simulates the operation of the Company's generating system and purchased power sources to meet projected customer demand." 8 TR

1498. This model also includes the availability of interchange power. 8 TR 1498. The total projected energy supply expense for the 12 months ending May 31, 2016 is $1,653,007,000. Exhibit A-59, page 1 of 3, line 28. This amount, together with the credit set forth on Exhibit A-59, page 3 of 3, line 57 ($196,819,000) as well as the test period transmission expense of $386,582,000, 8 TR 1497; Exhibit A-59, line 29, and the reagent expenses for pollution control equipment that are expected to be recovered as part of the Company's power supply costs in its PSCR proceedings, Exhibit A-59, lines 30-33, constitute the total fuel, purchased, and interchange power expense for the test year of $2,051,200,000. Exhibit A-59, page 1, line 34. That amount has been jurisdictionalized to reflect the amount to be included in the calculation of the Company's rates for the test period. 8 TR 1497. After adding in intersystem sales revenue the total fuel, purchased, and interchange power expense for the test year is $2,245,948,000.[14] Exhibit A-50 (HWM-5).

No other party contested this amount and the Staff accepted the Company's calculation of this expense. See, Exhibit S-3, Schedule C1, line 3. The Company has included this expense on Appendix C, line 1 (jurisdictionalized).

C. Other O&M Expense

1. Principles of O&M Expense Development

a. Company's Position

PA 286, MCL 460.6a, provides that, in preparing and filing a general rate case, "[a] utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." In Case No. U-15645, the very first rate case

[14] During the evidentiary hearing in this case Company witness Ronk noted that the fuel, purchased, and interchange expense amount contained on page 20 of his testimony should be revised downward to $2,051,200,000. 8 TR 1491. That adjustment is not included in the calculation of fuel, purchased, and interchange expense reflected on Appendix C to this brief.

decided by the Commission after the enactment of PA 286, the Commission noted that "[t]he basis for using a forward test year is to address the problem of regulatory lag between past and future costs." Opinion and Order, page 6 (dated November 2, 2009). Thus the Commission noted that the projected test year provision "recognize[s] that using projected data as a basis for rates may optimally reflect the cost of service contemporaneously with the effective period of the rates." *Id*. at 8. Despite considerable debate among the parties to that case, the Commission concluded that "[t]he debate regarding the proper test year was decided by the legislature and the Commission finds the use of a future test year to be the proper measure of projected costs and revenues." *Id*.

Nevertheless, the Commission, in Case No. U-15645, was still confronted with the difficult challenge of determining how to go about adopting "a new rate making model that challenges some of our traditional methods of determining the cost of service allocations, rate design, and revenue requirements." *Id*. at 6. The Commission recognized that "any time a State moves from a historical to a future test year the initial transitional year will naturally not follow the process used in those which preceded it, and will require a different standard of review." *Id*. In particular, the enactment of PA 286 would require the Commission to grapple anew with the question of "how the Commission should establish values for the various revenue, expense, rate base, and capital structure components used in the rate-setting formula." *Id*. at 7. The old ratemaking paradigm, before the enactment of PA 286, used a historical test year adjusted for "known and measurable" changes in a utility's costs. *Id*. at 6. However, the Commission also recognized that the new paradigm, enacted in PA 286, mandates that "the dynamics of determining costs requires a certain degree of forward projections that is not solely dependent on historical data." *Id*. The Commission concluded that what PA 286 requires is a "focus upon the

strengths and weaknesses of the evidentiary presentations of the parties regarding specific expense and revenue projections." *Id*. at 8 (emphasis added). The Commission held:

> "For future guidance, the Commission's expectation is that the parties will fully document the basis for their test year projections by offering into evidence detailed supporting explanations and underlying assumptions rooted in expected business, financial, and economic circumstances. Rate applications may not rely on undocumented estimates of future ratemaking expenses and revenue criteria. When necessary, parties should provide competing projections, with a similar basis of support. The record thus created should lend itself to a comparative review of the reasonableness and prudence of the projections. Historical data may play a role, but ordinarily will not be the controlling factor except in circumstances that clearly demonstrate that it is a more fair and reasonable reflection of the utility's cost of service, relative to projected data." *Id*. at 9 (all emphasis added).

In short, while PA 286 frees utilities from the limitations and procedural lag associated with historic test years, it also places on utilities and on any party offering "competing projections" the responsibility of developing detailed analyses regarding specific expenses and revenue projections in order to support those proposals.

Consumers Energy understands its responsibility to provide detailed support for expense projections, such as the Company's O&M expense forecasts, and employs systematic processes to develop the detailed and specific projections required by the Commission's Order in Case No. U-15645. Company witness Rochow provided high-level testimony in this case explaining the Company's process for developing expense forecasts for the projected test year. Mr. Rochow testified:

> "The individual witnesses addressing capital and O&M expenditures in this case address the reasons for these expenditures, and these expenditure levels undergo rigorous management review before they are submitted. The Company employs a thorough Portfolio Management Process which ensures that the allocation of O&M and capital resources are optimized such that our strategic, financial, and operational plans are aligned

> to deliver customer value. The Company maintains a portfolio of investment opportunities from which to make investment decisions, with the goal of maximizing customer value while minimizing the cost impact to our customers. While the Company must retain the flexibility to react to changing conditions, the proposed expenditure levels included in this case reflect the Company's commitment to meet it legal responsibilities and improve service reliability and quality. Approximately half of these expenditures relate to meeting legal and regulatory commitments. Further evidence of the Company's commitment to make the investments necessary to improve service would be the improvements in the customer service metrics noted throughout the testimony and exhibits filed in this case." 5 TR 161-162.

The Company's rigorous review process described above was designed to develop precisely the kind of detailed support for specific expense projections in this rate case that the Commission's precedent requires.

The Company's witnesses supporting projected O&M expenses all submitted testimony in this case consistent with the Company's process and the Commission's requirements. For example, Company witness Kehoe submitted testimony describing in detail how the specific expenses items that comprise his overall portfolio of Fossil and Hydro Generation-related O&M expense are developed for the test year. Mr. Kehoe testified:

> "Consumers Energy tracks the history and future maintenance needs of each unit. Personnel at each plant provide ERBS [Energy Resource Business Services] with information on maintenance for each site or specific unit. Based on that information, ERBS weighs the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding is available. After all appropriate levels of management have reviewed and approved the maintenance plan, a schedule is created. The overall objective is the safe, reliable, cost-effective generation of electricity." 6 TR 688.

Mr. Kehoe next explained how the Company weighs the estimated benefits to customers that are expected to result from each project. He continued:

> "The Company uses Internal Rate of Return ('IRR') and Present Value Ratio ('PVR') as a means to evaluate and weigh the hundreds of projects within Generation. IRRs and PVRs are calculated using standard Excel formulas. This complex financial model was developed in-house and allows the Company to calculate and measure the numerous changes that result when improvements (both O&M and Capital) are made to a regulated power plant. Only after the model has calculated the numerous changes that result from the proposed improvements can the projects IRR and PVR be calculated." 6 TR 688.

Mr. Kehoe then explained that the Company's Fossil and Hydro Generation O&M consists of two primary components: Base O&M costs and Major Maintenance costs. 6 TR 689. With respect to Base O&M costs, Mr. Kehoe explained:

> "Base O&M costs are determined by a generating unit's operating history and are broken into two categories – labor and non-labor. Labor is the primary component and has a predictable, stable rate of increase. Because most of the Company's units have been in service for over 40 years, we have an excellent basis to make accurate forecasts. Non-labor expenses also increase at a predictable rate and include items required to operate the plants. These items include, but are not limited to: 1) fuel (diesel and gasoline) for equipment and vehicles; 2) material; 3) tools; 4) cleaning supplies; 5) facilities; 6) security; and 7) road and grounds maintenance." 6 TR 689.

With respect to Major Maintenance costs, Mr. Kehoe provided extensive testimony regarding: (1) the specific plants that Company expects to require Major Maintenance projects during the test year; (2) the amount and distribution of those costs across the Company's plants; (3) the reasons the Company will incur those expenses; (4) the factors that contribute to differences in Major Maintenance costs from one generating unit to the next; (5) the categories of Major Maintenance projects; (6) the nature of the work involved in each category of Major Maintenance projects; (7) benchmarks for demonstrating that the Company is effectively managing its maintenance costs; and (8) and evaluation of the feasibility and reasonableness of incurring the projected costs during the test year. 6 TR 690-697. Based on these detailed

explanations of how the Company developed its test year projections, Mr. Kehoe sponsored Exhibit A-46 summarizing the Company's projected Fossil and Hydro Generation O&M expense. Exhibit A-46 represents the total sum of the detailed cost calculations described above for each specific project that the Company anticipates during the test year.

The record in this case contains similarly detailed testimony explaining the development of the specific expenses that are incorporated into the Company's projections for test year O&M expenses, including testimony on Electric Distribution O&M expense, 8 TR 1313-1330; SG O&M expense, 6 TR 942-943; IT O&M expense, 6 TR 838-844; Corporate Services O&M expense, 6 TR 641-651; Pension and Benefit O&M expense, 8 TR 1440-1483; and all other O&M expense items included in this case. These and other projections for the Company's test year O&M expense level are discussed further below. The Company's approach represents the appropriate process for developing and presenting O&M expense projections for purposes of a general rate case as set forth in the Commission's Order in Case No. U-15645. The Company's projections for O&M expense, as set forth in the following sections, are reasonable and appropriate and should be approved and adopted by the Commission for purposes of setting the Company's rates in this case.

b. Areas of Dispute with Staff

In contrast to the detailed analysis provided by Consumers Energy for each specific O&M expense item included in the Company's case, Staff proposes simply to adjust all of the Company's general O&M expense categories to the same level as assumed in the Company's January 2015 budget data book. 9 TR 1985. In support of this recommendation, Staff argues that it is "unreasonable to include O&M expense in rates at levels higher than those built into the most recent January 2015 Budget as provided to its Board of Directors." 9 TR 1992. However, Staff offers no explanation about why the Company's budget amounts for O&M are more

reasonable than the test year O&M expense projections included in the Company's case. Consumers Energy does not agree that they are.

Critically, Staff fails to understand that the Company's annual budget and the rate cases filing serve very different purposes. Whereas a rate case filing is designed to explain and support the full scope of the Company's expected expense and revenue needs in a future period of time in order to seek funds to meet all of its needs, the Company's annual budget must limit planning to address needed expenses in such a way that the Company can operate within the constraints of the resources it already has or reasonably can expect. In other words, a budget must make choices about which necessary and prudent expenses will be funded with the resources available and which expenses, though needed and prudent too, must be deferred to a later time at the risk of detrimental impacts on customer expectations for service and customer perception of value. The lower the expected revenue that can reasonably be incorporated into a budget, the higher the risk. In contrast, a rate case filing, such as this one, presents a proposal for funding utility operations that, if adopted, should eliminate or reduce those risks.

A prudently developed budget is necessarily constrained by conservative estimates of future revenues. On cross-examination, Staff witness Robert F. Nichols II agreed with that proposition. 9 TR 2005. Exhibit A-125 is a Consumers Energy response to a Staff audit question asking whether the Company incorporates any projections of future rate relief in its annual budgets. The response also explains the Company's budgeting philosophy. Exhibit A-125 states:

> "Budgeted revenues and expenses in the budget data book do incorporate some projections for future rate relief. However, the rate relief assumptions used in the data book are intentionally very conservative. It would be imprudent for the Company to plan on significant revenues that have not been approved by the Commission. Therefore, the data book is also necessarily

> aggressive in forecasting spending which may be lower than the Company's actual needs in future periods. The Company's rate case filing reflects the Company's complete forecast of its anticipated future needs during the test year. Any rate relief below the level requested in the Company's rate case filing would require the Company to make difficult choices between legitimate competing spending priorities." (Emphasis added).

Mr. Nichols also agreed on cross-examination that it would be imprudent for a business to budget for a total amount of expenses that exceeds the total amount of revenue or other sources of financing that the company expects to have available during the budget period. 9 TR 2005. In fact, when asked if that would be imprudent, his exact response was, "If you want to be profitable, yes." 9 TR 2005.

Consumers Energy witness Denato provided testimony demonstrating that, in fact, the Company's actual O&M spending levels over the past five years have typically exceeded the O&M spending levels included in the Company's budget assumptions.[15] 5 TR 433. Mr. Denato's testimony included the following table comparing annual budget amounts for O&M spending to actual O&M spending in the corresponding year:

Year	Budget	Actual	Spending H/(L) vs. Budget
2010	$ 641	$ 630	$ (11)
2011	$ 617	$ 654	$ 37
2012	$ 620	$ 664	$ 44
2013	$ 618	$ 661	$ 43
2014	$ 592	$ 625	$ 33
2015	$ 613	TBD	TBD
2016	$ 611	TBD	TBD
5-Year 2010-2014 Average	$ 618	$ 647	$ 29

[15] Staff's Exhibit S-11.10, page 2, shows that the test year amount of O&M requested by the Company in this case, excluding the Jackson Gas Plant, is lower than the Company's actual O&M expenditures in 2011, 2012, and 2013.

Staff attempts to argue that O&M spending only exceeds the budget in the years included in the table above because the Company exceeded its authorized rate of return on equity in those years. 9 TR 1999. But, Staff's own Exhibit S-11.17 shows that the Company's actual O&M spending sometimes exceeds budgeted spending even in years when the Company's earnings are lower than its authorized return on equity. Furthermore, Mr. Nichols admitted on cross-examination that he had performed no analysis of the Company's actual O&M expenditures for 2010-2014 and was not contending that any of the O&M expenditures during those years were unreasonably or imprudently incurred. 9 TR 2033-2039. Staff's criticism of comparisons of budget amounts versus the Company's recent actual O&M spending is without merit.

The Company's budget is necessarily conservative in its assumptions about future revenues that will be available to the Company and is, therefore, necessarily constrained in terms of the amount of money the Company can plan to spend during the budget year. As noted above, and in harmony with prudent budgeting principles, the Company is also necessarily aggressive in forecasting spending which may be lower than the Company's actual needs in future periods. Exhibit A-125. By way of analogy, it would be imprudent for an individual person to budget for expenses that exceed his or her expected income. That principle would remain true even if the expenses were to repair or replace a major home appliance, such as a furnace or hot water heater, that was showing signs of deterioration and the potential for catastrophic failure. But, the fact that such an expense may not be included in an individual's personal budget is not evidence that the expense is not needed and would not be reasonably or prudently incurred. Even if such a person subsequently asks his or her employer for a raise in order to defray those expected costs, it would still be imprudent to incorporate the requested raise into his or her budget before it was approved. This simple analogy illustrates why budgeted amounts for O&M spending are not

reasonable indicators of the reasonableness and prudence of the Company's proposed test year O&M expense in this case.

In addition, Staff's proposal to reduce the Company's projections of O&M expense for the test year, excluding the Jackson Gas Plant, by nearly $34 million constitutes a "competing projection" to the Company's O&M projections for the test year in this case. However, Staff's proposal, which, as noted above, is based solely on their unsupported assertion that the O&M assumptions included in the Company's 2015 budget are a more reasonable forecast of test year O&M expenses, fails to satisfy the Commission's mandate regarding the proper way to develop and support "competing projections" of test year expense forecasts in rate cases under PA 286. Unlike the Company's filing, Staff's proposal did not offer "evidentiary presentations of the parties regarding specific expense and revenue projections." MPSC Case No. U-15645, page 8 (emphasis added). In fact, Mr. Nichols' testimony on cross-examination was that he preferred just the opposite of an analysis of *specific* expenses. He testified:

> "My recommendation to use the budget amount was not based on any one particular line item. It's kind of cherry picking if you get into looking into particular line items that may go one way or the other way. My recommendation was to look at the total O&M as a whole and make a recommendation on it." 9 TR 2021.

Staff's presentation also did not provide "detailed supporting explanations and underlying assumptions rooted in expected business, financial, and economic circumstances." MPSC Case No. U-15645 at 9. On cross-examination, Mr. Nichols admitted that, in preparing Staff's presentation in this case, he had not performed any analyses similar to the detailed analyses performed by the Company's witnesses in this case. 9 TR 2022-2034. Summing up a lengthy line of questioning on that issue comparing the analysis performed by Company witness Kehoe, as an example, to the analysis performed by Staff, Mr. Nichols testified:

"Q. Mr. Nichols, the series of cross-exam questions that I have been asking you most recently pertain to sort of a detail by detail review of the kinds of analysis that the Company performed in order to develop its O&M expense amounts. Would you agree with that?

"A. Yes.

"Q. Would you agree that for the vast majority of the line items shown on your Exhibit S-3 Schedule C5, that you did not perform similar analyses to the kind of analyses we have been talking about in the last dozen or so questions?

"A. Yes, that is correct." 9 TR 2033-2034.

Throughout that testimony, Mr. Nichols admitted repeatedly that he had no basis to form a conclusion about the reasonableness or prudence of any specific line item of O&M expense included in the testimony of Company witnesses in this case. 9 TR 2022-2034. Staff simply did not review the details, nor did Staff perform its own detailed analysis. Yet the Commission has made it clear that a party providing a "competing projection" needs to provide a "similar basis of support" as the Company is expected to provide in a rate case under PA 286. *Id.* Staff did not meet that standard in this case. For all of the reasons stated above, Staff's proposal to simply substitute all of the Company's specific and detailed evidence on the appropriate level of test year O&M expense in this case with a short-cut proposal to use the Company's 2015 budget amounts for O&M should be rejected.

2. <u>O&M Expenses by Categories</u>

a. <u>Distribution and Energy Supply O&M (Non-AMI)</u>

(i) Company's Position

Company witness Palkovich testified concerning the O&M expense projections for the Electric Distribution Department. Ms. Palkovich projects the electric distribution O&M expenses to be $245,544,000 for 2014; $226,386,000 for 2015; and $239,439,000 for the test

year. 8 TR 1313; Exhibit A-51 (MPP-1). The projected test year expenses consist of $244,324,000 for the Electric Division; a $6,504,000 reduction due to the Smart Energy Direct O&M benefits; and $1,619,000 for Customer Value Initiative. Exhibit A-51 (MPP-1).

The majority of the O&M expenses on Exhibit A-51 (MPP-1) are for the Electric Division, and the expenses represent activities associated with: (1) Electric Energy Operations; (2) Electric Energy Delivery; and (3) Electric Customer Operation (excluding uncollectible write-offs). 8 TR 1323-1324. Ms. Palkovich testified that the Company has projected Electric Division test year O&M expenses to meet customer service and safety requirements. 8 TR 1314. The projected test year O&M expense for the Electric Division is $8,167,000 lower than the Company's 2013 actual Total Electric Division Expenses. 8 TR 1316. The difference between the expense levels is comprised of: (1) a $27,200,000 reduction of expenses associated with the December 2013 ice storm; (2) a reduction of $19,700,000 related to a plan to capitalize pole-top hardware replacement; (3) an increase of $28,900,000 in line clearing; (4) an increase of $3,700,000 in Smart Energy Customer Program expenses; (5) an increase of $3,900,000 in distribution technology improvements; and (6) an increase of $3,200,000 in North American Electric Reliability Corporation ("NERC") distribution compliance cost and costs associated with NERC Transmission Owner ("TO")/Transmission Planner ("TP")/Transmission Operator ("TOP") standards compliance. 8 TR 1316.

The Company is projecting $57,700,000 for its line-clearing spending for the test year. This requested line-clearing expense level consists of $53,300,000 for the LVD line clearing and $4,400,000 for the Company's HVD line-clearing program. 8 TR 1317. This funding level will permit clearing of approximately 25%, or 1,170 miles, of the HVD system, and approximately 14%, or 8,000 miles, of the primary LVD system annually. 8 TR 1318. Based on the

recommendations of an outside consultant, Environmental Consultants Inc., the Company's projected expense level supports the utilization of a seven-year average cycle for its LVD line-clearing program, and will allow the Company to address dead or dying hazard trees that are up to 20 feet outside of the right-of-way. 8 TR 1317-1318. Approval of this level of expense will assist the Company's overall line-clearing goal of improving the reliability of the electric distribution system while minimizing the long-term unit cost per mile for line clearing. 8 TR 1321.

The Electric Division's projected O&M expense includes $3,700,000 for Smart Energy Customer Programs. 8 TR 1322. This expense is for the marketing and enrolling customers in demand response programs. As the Company did not have these programs in place in 2013, the Smart Energy Customer Programs' projection is based on vendor estimates of customer acquisition costs. To ensure reasonableness, the Company benchmarked these estimates against utilities offering similar programs. 8 TR 1322.

Company witness Palkovich projected an increase in Electric Division O&M expenses in the amount of $3,900,000 for Distribution Technology. 8 TR 1322. These expenses are related to ongoing expenses associated with the deployment of technology in the Electric Division for a number of different projects such as: (1) an electric distribution historian to capture and archive an increasing amount of system data; (2) an interface between a Geographical Information System and the Outage Management System ("OMS"), which allows geographical location data to be associated with electrical assets in the field;(3) grid communication modernization; (4) a meter operational data manager historian; (5) a OMS/SG user interface; and (6) capacitor control maintenance. 8 TR 1322.

An increase in O&M expense in the amount of $3,200,000 is projected due to additional distribution and transmission NERC compliance costs. 8 TR 1322-1323. Ms. Palkovich testified that a portion of the increase in costs is related to the Company's intention to register as a TO/TOP/TP. 8 TR 1322. This requires the Company to comply with approximately 200 NERC requirements. 8 TR 1323. Additionally, distribution compliance costs are increasing due to the NERC PRC-005-2 protection system maintenance and testing standard, which requires more components being inspected and/or tested, rigorous documentation requirements, and significantly more complex field testing. 8 TR 1323. Due to the change implemented by NERC, Ms. Palkovich testified that the Company's increase in funding "…is necessary to support the additional technical and field resources needed to implement and sustain the expanded protection system maintenance and testing program that would comply with the new standard." 8 TR 1323.

(ii) Areas of Dispute with Staff

Consumers Energy requests that the Commission reject the Staff's proposed Electric Division O&M expense reductions. Staff inappropriately used the Company's budget projections as a basis for the proper O&M expenses level; however, budget projections are not an accurate reflection of actual spending. See Section V.C.1. of this Brief for a detailed discussion. Additionally, Staff further reduced the Electric Division's O&M expense level to account for a lower forestry spending amount. The Commission should adopt the Company's projections as a more reasonable projection of Electric Distribution O&M expenses as the Company has shown it is willing to spend in excess of the Electric Distribution Department's rate approved amounts in order to provide additional customer benefits. 8 TR 1353.

Staff supports the adoption of an Electric Distribution O&M expense in the amount of $213,370,000 for the projected test year. This expense level was based solely on the Company's

budget book. 8 TR 1363. As explained previously above, the budget book does not provide for reasonable projections for the Company's test year expenses. In fact, the Company's budget book is not reflective of actual Electric Distribution O&M spending. Review of Exhibit S-11.10, page 2, shows each year since 2011 the actual amount for the Electric Distribution O&M has far exceeded the budgeted amount. The exhibit further shows that the Company has historically spent more than the amount of Electric Distribution O&M expenses that have been approved in rate filings. See also 8 TR 1362.

Setting a reasonable O&M expense level for the Company's Electric Distribution Department will benefit customers. By spending more than what is approved in rates, the Company's reliability metrics have improved. 8 TR 1362. Exhibit A-115 (MPP-10) shows improvements made in the recent five-year trends for System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and System Average Interruption Duration Index ("SAIDI") (excluding major event days). 8 TR 1362-1363.

The Company's actual Electric Distribution O&M spending illustrates the reasonableness of using its projections rather than Staff's amounts. Staff's methodology will arbitrarily set an expense amount that will not allow the Company to continue the improvements in reliability and customer satisfaction. 8 TR 1364. The Company's projected Electric Distribution O&M expenses are the appropriate amount to meet customer service expectations, continue to improve reliability, and to meet safety requirements. 8 TR 1364.

In addition to its proposed budget adjustment, Staff contended that there should be a reduction in the Company's line-clearing expense. Staff witness Laruwe testified in favor of $44,550,000 for routine tree trimming, which is based on the last Commission approved amount, and an additional $3,950,000 for addressing hazardous trees outside of the right-of-way

("ROW"). 9 TR 1906. Staff's use of the historic line-clearing expense level ignores evidence demonstrating the basis for and benefit of the projected line-clearing expense amount. 8 TR 1351. By relying on an historic spending level, Staff fails to recognize that the historical average level of forestry spending did not adequately address the overall system tree conditions, and by increasing the amount of line-clearing spending from historical levels, Consumers Energy will be better equipped to reverse the growing trend of tree caused outages and reduce the related service restoration time. 8 TR 1351.

Ms. Palkovich provided extensive testimony in support of the Company's line-clearing expenses. 8 TR 1317-1321, 1351-1356, 1364-1367. From 2009-2013, Ms. Palkovich testified that trees on average caused approximately 21% of customer interruptions. 8 TR 1318. The trend continues to increase. 8 TR 1319. In order to appropriately address this outage trend, there needs to be an increase in the amount of line-clearing spending and a reduction in the Company's clearing cycle length. 8 TR 1319. This has been recognized by the Commission. In MPSC Case No. U-17542, the Commission encouraged Consumers Energy to continue with vegetation management improvements and to expand it vegetation management program to address trees outside of utility easements. See MPSC Case No. U-17542, Order, May 2, 2014, p. 24; see also 8 TR 1351.

The Company's proposed vegetation management program and projected expense level will improve customer reliability by annually clearing 14% of the LVD system and maintaining the current practice of annually clearing 25% of the Company's HVD system. 8 TR 1351-1352. The Company's proposed vegetation management program is consistent with the finding of Environmental Consultants Inc. ("ECI"), who performed a study to determine the optimal cycle of clearing for the Company's electric distribution system and, based on current vegetation

conditions of the Company's LVD system, recommended clearing 14% of the LVD system annually. 8 TR 1352. As part of its program, Staff witness Laruwe suggests the Company address circuits with higher than normal vegetation-caused outages. 9 TR 1907. This is already being done. The Company's proposed program is based on addressing full circuits with higher than normal vegetation-caused outages, as determined by the Reliability Analytics Engine model. 8 TR 1355. Repetitive outage clearing is also being performed to clear individual circuit sections where customers are experiencing high numbers of outages. 8 TR 1355.

While Staff does not appear to disagree with the Company's proposed vegetation management program, Mr. Laruwe expressed concern that the funding for line clearing is partially dependent upon the emergence of storms in a given year. 9 TR 1904-1905. The Company must manage its spending across the utility portfolio, and funding for line clearing, service restoration, and the Company's overall spending must be balanced. 8 TR 1352. However, the Company has made efforts to mitigate the impact that service restoration expenses have on overall O&M expense through projects like the pole-top capitalization. 8 TR 1354. As Ms. Palkovich testified:

> "By reconfiguring its work order system to allow for the plant unitization of pole-top hardware, the Company will be able to capitalize some demand replacement pole-top hardware costs that are currently O&M expenses in service restoration, corrective maintenance, and HVD lines demand programs. It is estimated that approximately $19,700,000 per year can be reduced in direct O&M expenses in service restoration, corrective maintenance, and HVD lines demand once these new plant units are established. This movement of these O&M expenses to the capital Demand Failures Program is the reason the expenditures in that program are projected to increase but will mitigate the effects of the large increases in O&M expenses the Company may experience in periods of heavy storm activity." 8 TR 1354.

As a whole, Consumers Energy is committed to allocating all resources possible to continue to improve reliability, and this will be possible with the total O&M funding projected in this rate filing. 8 TR 1352-1353.

In conjunction with the Company's clearing of hazardous trees outside of the ROW, Staff proposed that certain information be collected regarding the ROW Program. 9 TR 1906-1907. This proposal would be difficult to implement as the Company's system is not configured to provide some of Staff's requested data, and the collection of this information would be expensive. 8 TR 1355. As an example, Ms. Palkovich testified that "providing the number of outages caused by trees outside the ROW and the customer acceptance of the program (metrics 1 and 4) would require changes to the Outage Management System ('OMS'), the INVPROD Program, and training for data collectors." 8 TR 1355. Also, it is unclear what Staff envisioned when they proposed collecting information with respect to "[a]ll complaints regarding the outside the ROW program," and the Company does not currently track informal complaints. 8 TR 1355. While the Company disagrees with the specifics of Staff's proposal, Consumers Energy would be willing to meet with Staff and other interested parties as part of a collaborative effort to determine what data would be available and useful for an analysis of the ROW program. 8 TR 1355.

(iii) Areas of Dispute with the Attorney General

The Commission should reject the Attorney General's proposed disallowances. The Attorney General proposed adjustments to the Company's O&M expenses related to Vegetation Management-Tree Clearing, Smart Energy, Technology Support, and NERC Standards Compliance costs. 10 TR 2277. These adjustments are unwarranted and Consumers Energy requests that the Commission adopt its Electric Distribution O&M expenses.

Consumers Energy requests the Commission reject the Attorney General's proposed forestry spending level of $40,000,000. 10 TR 2279. Mr. Coppola suggests the Company's test year line-clearing spending levels should be based on the Company's historical line-clearing spending levels. 10 TR 2277-2279. As with Staff witness Laruwe, Mr. Coppola's rationale in determining his proposed forestry spending is not based on what is needed to make improvements in reliability and reduce outages. 8 TR 1351-1353. As discussed previously in this Brief, the Company is requesting to increase its vegetation management program to $57,000,000. This level of expense will allow line clearing of approximately 14% per year on the LVD system (an seven-year effective clearing cycle) and will maintain the current practice of annually clearing 25% of the Company's HVD system. Approval of this level of expense will enable the Company to continue to make improvements in overall system reliability for the benefit of customers. 8 TR 1364.

In an attempt to bolster his proposal, Mr. Coppola attempts to use the ECI study as support for his proposed line-clearing expense reduction. After reviewing the ECI study, Mr. Coppola recommends using an eight-year line-clearing cycle, which would require $43 million in expenses in the initial first cycle and $34.4 million in the subsequent annual maintenance cycle. 10 TR 2278. To achieve his forestry O&M expense recommendation, Mr. Coppola averaged the cost of the initial clearing cycle with the cost of the annual maintenance clearing cycles. 10 TR 2278. This recommendation is flawed. Without explanation, the Attorney General's proposal strays from the ECI study's seven-year clearing cycle recommendation and ignores the fact that the ECI study did not include any proposals related to the Company's HVD system. 8 TR 1366. Further, it is patently unreasonable to average the expected second cycle line-clearing expenses with the first cycle line-clearing

expenses. 8 TR 1366. This is because the amount of money needed to clear the system through the first cycle is significantly higher than the funds needed for the maintenance clearing cycles. 8 TR 1366. The use of an average amount will not allow the Company to complete clearing in the cycle timeframe, and as the cycle time lengthens, the cost to clear a circuit mile increases. 8 TR 1366. Ms. Palkovich stated:

> "The ECI analysis used current density of vegetation on the Company's system to derive the first cycle line-clearing costs per year and predicted vegetation density to determine the second cycle line-clearing costs per year. Using an average cost for the two cycle periods would result in a ten-year timeframe to complete the first cycle line clearing. This is due to the higher cost associated with the first cycle line clearing based on vegetation density. Additionally, this assumes that all dollars would be used on the LVD system. Thus, there would be no funding to clear the HVD system." 8 TR 1366.

As Mr. Coppola's recommended forestry program is based on historical spending levels and a flawed interpretation of the ECI study, the Company requests the Commission reject Mr. Coppola's line-clearing expense recommendation.

Attorney General witness Coppola also proposes to reduce Consumers Energy's Smart Energy Customer Program O&M expense level by $1,800,000 to a test year amount of $1,900,000. 10 TR 2279-2280. This proposed reduction is unsupported by the record. The only rationale Mr. Coppola offers for the proposed disallowance is that the Company did not provide specific information about the program. 10 TR 2280. This is incorrect. Mr. Warriner provided extensive information both in direct rebuttal and in cross. As previously discussed, the Smart Energy Customer Program expense is for the marketing and enrollment of customers in demand response programs such as dynamic pricing and DLA. 8 TR 1322. As seen in Exhibit AG-6, sufficient details for the Smart Energy Customer Programs were provided. Mr. Coppola's

recommended reduction is arbitrary, and the Commission should approve the Company's projected expenses for the Smart Energy Customer Program.

The Attorney General next recommends reducing the Distribution Technology Projects O&M expense level by $2,000,000 to a test-year amount of $1,900,000. 10 TR 2280-2281. This proposed reduction is based on his conclusion that the capital projects would not be operational during the test year. 10 TR 2280. This contention is unsupported. Mr. Coppola provides no evidence to support his conclusion that these projects will not be operational, and in addition to the Company's testimony, Exhibit AG-6 shows that Mr. Coppola was provided information as to the necessity and details behind these expenses. 8 TR 1367. The Attorney General's proposed reduction should be rejected, and the Commission should adopt the Company's projected Distribution Technology Projects expenses.

Consumers Energy requests the Commission approve the Company's proposed O&M expenses related to NERC compliance. Without explanation or evidentiary support, Mr. Coppola questioned the portion of O&M expenses related to the Company's registration as a TO/TP/TOP, reducing them by $2 million, indicating that "it does not appear to be clear even to the Company what the additional registration as a TO/TP/TOP entity really means." 10 TR 2281. This suggestion is without merit. The Company is well-aware of what it means to register as TO/TP/TOP entity and the standards that need to be complied with. 8 TR 1368. Mr. Coppola's proposed reduction in expenses ignores the fact that there are over 200 NERC requirements associated with being a TO/TP/TOP that must be complied with prior to registering in October 2015. 8 TR 1368. This includes maintaining a compliance program and associated procedures on ongoing basis. 8 TR 1368. This will be established by mid-2015, as well as the hiring of additional employees and the creation of a training program to develop and maintain

the necessary NERC certified operators and support personnel. 8 TR 1369. The Attorney General's proposal disregards NERC compliance measures the Company must undertake and his proposed expense reduction should be rejected.

b. Fossil and Hydro Generation O&M Expense (including the Jackson Gas Plant)

(i) Company's Position

Company witness Kehoe, Director of Staff Electric Generation, testified concerning the projected O&M expense for the Company's Fossil and Hydro Generation Department. Mr. Kehoe projected the test year level of O&M expense for that department at $176,827,000. 6 TR 685; Exhibit A-46 (DBK-3). The Test Year Base O&M was calculated using a linear regression which results in annual decreases of 9.1%. 6 TR 686. Projected expenses were adjusted for: (1) environmental operations, (2) the Jackson Gas Plant, and (3) Major Maintenance. 6 TR 686. As explained by Mr. Kehoe, the Company tracks the historical and future maintenance needs of each generating unit. 6 TR 688. Personnel at each plant provide the Fossil and Hydro Generation Division with maintenance information, which is then used to determine the priority of the maintenance projects to be addressed. 6 TR 688-689.

The Company's Environmental Operations O&M expense is attributable to federal and state emissions standards. 6 TR 687. To comply with these federal and state standards, the Company is installing AQCS. 6 TR 687. As the number of AQCS devises increase, so do the costs to operate and maintain these critical pieces of equipment. 6 TR 687. Moreover, the Company's Jackson Gas Plant O&M expense is related to the 540 MW natural gas-fueled power plant located in Jackson, Michigan that the Company intends to purchase. 6 TR 687. This specific expense is comprised of Labor, Material, and LTSA obligations. 6 TR 687.

Mr. Kehoe further explained that O&M expense spending in the generation area is split into "Base" and "Major Maintenance" components. 6 TR 689. The Base O&M costs are determined by each generation unit's operating history and are broken down into labor and non-labor components. 6 TR 689. Base O&M costs are fairly predictable. 6 TR 689. Major Maintenance costs are not consistent and vary each year by generating unit. 6 TR 692.

Major Maintenance is further divided into Outage and Non-Outage classifications. 6 TR 693-694. Outage maintenance O&M costs are those associated with major overhauls and require the generation unit to be removed from service for boiler or turbine inspections and maintenance. 6 TR 693. The Company has scheduled two turbine outages during the test year, one outage for Karn unit 1 and one outage for Campbell unit 3. 6 TR 695. Non-Outage maintenance typically does not require the generating unit be removed from service; however, this maintenance is still critical to the operation of the unit. 6 TR 695. Mr. Kehoe listed the Non-Outage maintenance scheduled for the test year at 6 TR 695-697.

The requested O&M expenses are necessary and reasonable to continue Consumers Energy's successful operation of the generation fleet. 6 TR 695. The reasonableness of the Company's O&M expenses is made further evident by the fact that, despite operating the oldest regulated generating fleet in the nation, the Company's cost to generate electricity has been routinely ranked in the top 25% (i.e., least expensive) in the nation. 6 TR 684; 696.

(ii) Areas of Dispute with Staff

Staff witness Nichols proposes a $15,741,000 reduction to the Company's proposed Fossil and Hydro Generation O&M. 9 TR 1985. However, in proposing this reduction Mr. Nichols only points to a "budget book" that was presented to the Company's Board of Directors and provides no analysis which evaluates the reasonableness of the Company's

projected O&M expenses. This unsupported recommendation should be rejected by the Commission.

Mr. Nichols' reliance on the budget book, for the sole basis of his recommendation, is in error. See Section V.C.1. of this Brief for a detailed discussion. As explained by Company witness Denato, budgeted spending as reviewed by the Company's Board of Directors, should not be viewed in isolation to predict the Company's appropriate O&M expense. 5 TR 433. In addition to the budget, historical actual results versus original budget amounts should be reviewed, along with Company O&M witness testimony. 5 TR 433. Actual spending, which routinely has been higher than the budget for the last several years, represents the level of spending necessary to achieve safe and reliable service as well as needed services and upgrades. 5 TR 433.

The Company's evidence in support of its projected Fossil and Hydro Generation O&M, as provided by Mr. Kehoe, comprehensively considers a multitude of factors which includes past O&M spending and individual drivers of O&M expenses. Furthermore, Mr. Nichols conceded in cross-examination that he performed no analysis as to the projected Fossil and Hydro General O&M. 9 TR 2027-2028. Further, Mr. Nichols explained that, based on his lack of analysis, he "would have no way of knowing" if Mr. Kehoe's project Base O&M for the test year was correct. 9 TR 2028. On this basis, Mr. Nichols' recommended reduction fails to pass muster.

Additionally, even if the budget book did provide proper support for reductions, which the Company disagrees, there is still no basis to reduce Fossil and Hydro Generation O&M based on the budget. Company witness Kehoe explained that projected 2015 Fossil and Hydro Generation O&M amounts in this case are actually slightly lower than amounts approved by the Board of Directors in the budget. 6 TR 722. Furthermore, the Company's projected 2016 Fossil

and Hydro Generation O&M amounts are below the amounts contained in the long-term financial plan for 2016. 6 TR 722. Thus, the budget does not support any reductions to the Company's project Fossil and Hydro Generation O&M amounts.

The Company's Fossil and Hydro Generation O&M projections in this case are the costs required for the Company to continue to be able to provide safe, reliable, and efficient electric generation. 6 TR 723. The cost projections are the result of a comprehensive process that utilizes historical analysis, Internal Rate of Return ("IRR") and Present Value Ratio ("PVR") analyses, and senior management approval. 6 TR 724. Moreover, the Company has consistently spent the amounts that it has requested for Fossil and Hydro Generation. 6 TR 724-725.

Therefore, as a result of the above flaws in Staff witness Nichols' recommendation and the extensive analysis presented by the Company which support its Fossil and Hydro Generation O&M amounts, Staff's proposed reduction to Fossil and Hydro Generation O&M should be rejected by the Commission.

(iii) Areas of Dispute with the Attorney General

Attorney General witness Coppola's proposed $12.9 million in reductions to the Company Fossil and Hydro Generation O&M should be rejected by the Commission. 10 TR 2282-2284. At the foundation of Mr. Coppola's recommendation is an arbitrary declaration that certain costs will not be incurred within the test year and a failure to comprehend the importance of setting accurate operating costs at the Company's generating units.

Mr. Coppola argues that Environmental Operations Fossil and Hydro Generation O&M should be reduced because "the Karn and Campbell plants are not scheduled to go into services until April 1, 2016 and June 1, 2016." 10 TR 2282-2283. This is incorrect. The Karn plant began operating the referenced emission controls in June 2014 to ensure compliance with the

MATS. 6 TR 726. Campbell units 1, 2, and 3 were given a one-year extension for compliance with MATS and will begin operating the referenced emission controls in February 2016. 6 TR 726. Additionally, the Company has projected a full year of expense at these units to allow full recovery of the Environmental Operations revenue requirement. 6 TR 727. All emissions equipment in question will become operational during the test year and customers will receive the full benefit of this equipment when it becomes operational. 6 TR 727. Mr. Coppola's recommendation inappropriately restricts the Company's recovery of emission control equipment that will be operating well beyond the end of the test year. 6 TR 727.

Similarly, Mr. Coppola's reduction to Jackson Gas Plant O&M fails to appropriately capture the Company's operating costs. The Company has included a full year of 2016 operating expenses for the Jackson Gas Plant to allow full recovery of the plant's revenue requirement. 6 TR 728. If the Company were forced to use a revenue requirement based on the purchase date of the plant, as suggested by Mr. Coppola, the Company would collect only five months of the full revenue for a plant that will be operating well beyond the test year in this case. 6 TR 728. The Jackson Gas Plant will be purchased and become operational during the test year in this case and customers will receive the full benefit of the Jackson Gas Plant beginning on day one of commercial operation. 6 TR 728.

Thus, Mr. Coppola's proposed reductions to Fossil and Hydro Generation O&M should be rejected by the Commission. Mr. Coppola's recommendation presents incorrect conclusions with respect to when the Company will incur environmental costs and fails to capture the importance of setting accurate operating costs at the Company's generating units.

c. Corporate Service O&M Expense

(i) Company's Position

Company witness Daniel L. Harry, Director of Accounting Process and Control, testified concerning the Corporate Services O&M projections. Mr. Harry calculated the projected test year Total Adjusted Corporate Services O&M to be $54,285,000 which was calculated from the 2013 actual and projected amounts for 2014, 2015, and the 12-months ended May 31, 2016. 6 TR 644; Exhibit A-29 (DLH-1). The test year O&M was calculated by using the 2013 actual expense and then applying inflation factors for labor and non-labor not to exceed the Consumer Price Index. 6 TR 644-645; Exhibit A-30 (DLH-2). Additionally, total Corporate Services expenses are normalized for significant increases or decreases related to unusual and/or one-time costs. 6 TR 645-646. Further, disallowances were incorporated to account for various items that have been previously disallowed by the Commission. 6 TR 647.

Corporate Services O&M expense includes expenses for: Human Resources and Administrative Services, Internal Control and Compliance, Legal, Corporate Risk Management, Corporate Secretary, Governmental/Public Affairs and Corporate Compliance, Controller's Area, Rates and Regulation/Regulatory Affairs, Strategy and Research, Strategic Innovation, Corporate Tax, Financial Planning and Treasury, General Activities costs, and Administrative and Other costs. 6 TR 641-642.

Consumers Energy's Corporate Services O&M expenses are reasonable, a conclusion supported by the fact that SNL Datasource[16] ranked the electric side of Consumers Energy's administrative and general costs (excluding Pension and Benefits) fourth lowest out of 66 on a

[16] The SNL Datasource is maintained by SNL Financial LC. SNL Datasource provides financial and operating data for electric utility companies. 6 TR 647.

cost-per-customer basis for electric companies with over 500,000 customers. 6 TR 647; Exhibit A-31 (DLH-3).

Including uncollectible expense, injuries and damages, and accounts receivable sales costs, the Company reasonably projects Corporate Services O&M expense in the amount of $90,451,000 for the test year. Exhibit A-29 (DLH-1).

(ii) Areas of Dispute with Staff

Staff witness Nichols' proposed reduction to insurance expense in the amount of $2,504,000 should be rejected by the Commission. 9 TR 1991. Mr. Nichols' recommendation fails to reflect the nature and frequency of Company insurance refunds and/or credits.

Mr. Nichols' insurance cost recommendation assumes a significant amount of insurance refunds and/or credits will be received annually by the Company for the foreseeable future. 6 TR 660. This is not the case. The receipt of insurance refunds and/or credits has historically been, and is expected to continue to be, very sporadic due to the volatility of investment markets and future claims experience. 6 TR 660-661. As a result of this sporadic nature, the timing and amount of future refunds and credits cannot be relied on to occur with any certainty. 6 TR 661. These sporadically received amounts should be treated as non-recurring items and normalized out of ongoing expenses. 6 TR 661.

On this basis, Mr. Nichols' recommendation to reduce the Company's projected insurance expense should be rejected. Mr. Nichols' recommendation unreasonably assumes that insurance refunds and/or credits are recurring in nature.

d. IT O&M Expense

(i) Company's Position

Company witness Varvatos testified concerning the O&M projections for the IT Department. Exhibit A-70 (CJV-2) shows the projected O&M expense levels for each major category. Mr. Varvatos projects the 2014 IT O&M expense to be $44,989,000; the 2015 IT O&M expense to be $43,717,000; and the test year O&M expense to be $41,411,000. 6 TR 839; Exhibit A-70 (CJV-2). These projections were based on a 2013 actual amount of $36,349,000, which was taken from Consumers Energy's internal records. 6 TR 838-839. This amount was adjusted for known and measurable changes. 6 TR 840-842.

The Company's IT O&M expenses are separated into the Operations and Investments categories. Operations expenses include internal and external labor costs associated with the Company's software systems and the computing infrastructure, software licensing, and contracts associated with the Company's computing infrastructure and communications networks. 6 TR 839. For 2014, 2015, and the test year, Mr. Varvatos projected an increase in Operations O&M expenses due to hardware maintenance for cyber security applications, contractual increases, maintenance costs for new applications going into production, increases associated with SAP, and an increase in business expenses. 6 TR 840-841.

Investment O&M expenses tend to vary more than Operations expenses. This is because Investment O&M expenses include the costs associated with capital projects and programs such as data conversion costs, training costs, costs incurred during the preliminary project stage, and costs incurred after all substantial testing of the project is complete. 6 TR 840-841. For 2014, 2015, and the test year, Investment O&M expenses are increasing due to the costs associated

with a number of capital projects including the Field Mobility Program, the Call Center Infrastructure Refresh project, and Business Partner funded projects. 6 TR 840-841.

For the test year, the Company's requested IT O&M expense is 5.3% lower than its projection for 2015. Company witness Varvatos projected that the O&M Operations cost for the test year will be within 0.2% of the 2015 O&M Operations expense levels, and that IT O&M Investment expenses will be 20% lower due to lower O&M costs associated with strategic and Business Partner funded projects planned in the test year. 6 TR 841-842. The projected O&M expense is a reasonable and appropriate level to provide the necessary IT service for Consumers Energy 6 TR 841-842.

(ii) Areas of Dispute with Staff

Consumers Energy requests the Commission reject Staff witness Nichols' proposed $1,762,000 reduction to the Company's IT O&M expense. Exhibit S-3, Schedule C5, line 2, column e. Mr. Nichols' proposed disallowance to IT O&M expense is based solely on the Company's budget (9 TR 1993) and does not include the O&M expenses associated with the Company's cyber security program. 10 TR 2129.

Although asserting that the Company's budget data book is a better indicator of the level of O&M expense necessary to provide reliable service (9 TR 2002), Staff witness Nichols admitted that he did not perform a detail-by-detail analysis when adjusting the Company's O&M expense. 9 TR 2033-2034. Instead, the Staff relied upon the Company's budget, which is based on assumptions that do not necessarily utilize the comprehensive cost projection process that the Company undertakes in preparation for electric rate case proceedings. 6 TR 867; See Section V.C. of this Brief for a more detailed discussion. Mr. Varvatos testified that the Company's comprehensive IT cost projections differ from the budget. 6 TR 886-887. Moreover, this was

previously explained to Mr. Nichols. During the audit process, Staff witness Nichols indicated that Company advised him of the differences between the budget and its expense projections in this case. 9 TR 2012. The Company explained that:

> "the rate relief assumptions used in the data book are intentionally very conservative. It would be imprudent for the Company to plan on significant revenues that have not been approved by the Commission. Therefore, the data book is also necessarily aggressive in forecasting spending which may be lower than the Company's actual needs in future periods. The Company's rate case filing reflects the Company's complete forecast of its anticipated future needs during the test year." 9 TR 2012-2013

In disregarding the differences between the Company's projected expense level and budget expense level and not providing an analysis on the Company's IT O&M expense projection, the Staff's proposed disallowances is unreasonable. The IT O&M expenses projected in this filing are the appropriate amount in order to meet customer service expectations, and as a result, Staff's projected IT O&M expense should be rejected.

(iii) Areas of Dispute with the Attorney General

The Commission should reject the Attorney General's proposal to reduce IT O&M expenses by $1,700,000 for the test year. 10 TR 2285. Mr. Coppola proposed reducing O&M expenses in the Investment category based on a misunderstanding of a Company discovery response. Although the Company projects test year Investment O&M expenses of $9.6 million, Mr. Coppola alleged that the Company only identified $7.9 million in expenses and, thus, the remaining amount should be disallowed. 10 TR 2285. This is not accurate.

As seen in Exhibit A-118 (CJV-6), the Attorney General only requested the project O&M expense associated with each of the IT capital projects from 2013-2015 and the test year. 6 TR 868. However, there are Investment O&M expenses that are not directly tied to a particular project. Company witness Varvatos testified that origination costs are included in Investment

O&M expenses and origination costs are not project specific. 6 TR 868. Origination costs should be included in O&M expenses because these costs are incurred during the idea phase of the project. 6 TR 868. During the idea phase, the Company explores different projects and develops and identifies the project benefits and costs. The conclusion of the idea phase results in a determination whether to move forward with different IT projects. 6 TR 868, 891. As origination costs are reasonably included in the Company's projected O&M expense, the Attorney General's proposed disallowance is unwarranted.

e. Pension and Benefit O&M

(i) Company's Position

For the projected test year, the Company proposed a total electric O&M expense level for employee benefits of $73,255,000. Exhibit A-43. This test year employee benefit O&M expense amount is comprised of: (1) a Pension Plan expense of $ 37.447 million; (2) a Defined Benefit Supplemental Executive Retirement Plan ("DB SERP") expense of $4.588 million; (3) a Defined Company Contribution Plan ("DCCP") expense of $5.738 million; (4) a Defined Contribution Supplemental Executive Retirement Plan ("DC SERP") expense of $159,000; (5) a 401k savings plan expense of $7.012 million; (6) an active employee health care, life insurance, and long-term disability insurance ("LTD") expense of $27.534 million; and (7) a retiree health care and life insurance expense of ($9.223 million).

To support the total electric expense level for employee benefits, the Company presented the testimony of Company witness Kops, Director of Employee Benefits. 8 TR 1435-1489. Mr. Kops is responsible for the design, implementation, and administration of the Company's retirement benefit and insurance benefit plans for employees and retirees. Additionally, he has the responsibility of administering the Company's self-insured workers compensation program,

absence management program, and the educational assistance program. 8 TR 1436. Exhibit A-49 (HBK-1) summarizes the electric O&M expenses for these retirement and insurance benefit plans offered to employees and retirees.

Pension Plan expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. 8 TR 1442. The electric utility's projected pension expense is $37.447 million for the 12 months ending May 31, 2016. 8 TR 1444. This expense is calculated using actuarial analysis that is performed by the Company's actuary Aon Hewitt in accordance with Accounting Standards Codification 715 ("ASC 715") using information specific to the Company's Pension Plan. 8 TR 1441-1442. The Company's auditors review the actuarial assumptions to insure consistency with Generally Accepted Accounting Principles ("GAAP"). 8 TR 1442.

For the year 2013, the actual electric utility O&M expense for pensions was $46,199,000. 8 TR 1443. For 2014, the electric utility's projected O&M pension expense is $23,909,000. The decrease in the 2014 projected pension expense was due to greater asset returns than expected, a Company cash contribution of $150 million to the Pension Plan in 2013, and an increase in the year-end market-based discount rate to 4.90%, up from 4.10%. 8 TR 1444. For 2015, the electric utility's portion of the projected O&M pension expense is $38,438,000. The projected 2015 pension expense increased due to an update to the Retirement Plans-2014 mortality table and a reduction in the discount rate used to project to 4.2%. 8 TR 1445.

There have been no benefit changes made to the Pension Plan since September 1, 2005 when the Pension Plan was closed to new hires. Yet, in order to have a competitive benefits package that attracts and retains qualified and talented employees, the Company replaced the Pension Plan with the DCCP for all new hires. 8 TR 1450. Under the DCCP, the Company

contributes a cash contribution of 6% of the employee's base wage into the 401(k) Employee' Savings Plan. This occurs regardless of whether an employee contributes to the 401(k) plan. 8 TR 1450. For the test year, the Company projects an electric DCCP expense of $5,738,000. Mr. Kops testified that the DCCP expense will continue to grow as all new employees will participate in this program and the Company continues to hire new employees to replace retirements. 8 TR 1451-1452.

The 401(k) Savings Plan is a 401(k) type retirement savings program funded by employee contributions. 8 TR 1455. The Company matches 60% of the first 6% of employee contributions. 8 TR 1455. For the test year, the electric utility O&M expense projected for the 401(k) Savings Plan is $7,012,000. Mr. Kops testified that the employer matching program is important to help provide a competitive benefits package that is needed to attract and retain qualified and talented employees. 8 TR 1457. Additionally, Mr. Kops testified that the Pension Plan and DCCP are not designed to fully meet the employees' retirement income needs and are only part of the overall competitive retirement package. 8 TR 1458.

Mr. Kops testified that DB SERP and DC SERP befits are necessary in order to attract and retain qualified executives. 8 TR 1447, 1453, and 1486. DB SERP is a common benefit structure available to officers and certain director level employees hired before April 1, 2006 that is designed to recognize certain provisions of the IRC relating to the amount of employee pay that can be considered in determining retirement benefits. 8 TR 1446. For the test year, the electric utility O&M expense for DB SERP is $4,588,000. Like the Pension Plan, the DB SERP projection is based on Aon Hewitt's actuarial determination of the plan's total expense for that year in accordance with ASC 715 and also includes plan administration fees. 8 TR 1448-1449. After April 1, 2006, the Company replaced DB SERP with DC SERP. 8 TR 1452. Under the

DC SERP, the Company provides an amount equal to 5%, 10%, or 15% of the eligible employee's earnings, depending on their pay grade, that exceeds the legislated earnings limits. 8 TR 1453. The change from DB SERP to DC SERP was made to coordinate with the qualified plan change to the DCCP from the defined benefit Pension Plan. 8 TR 1453. For the test year, the electric utility O&M expense amount for DC SERP is $159,000. 8 TR 1454. In the projected test year's SERP expense levels, the Company excluded the top six executives from its recovery request. 8 TR 1489.

Mr. Kops also addressed active and retiree health care, life insurance, and LTD expense. Mr. Kops testified:

> "While health care trends have recently moderated somewhat nationally, the Company's health plans indicate that the Company's workforce is older than the average in their plans, and, as a result, has a higher utilization rate of services that is associated with an older covered population. Of the Company's current workforce on December 31, 2013, 57% of employees are over age 45; 43% are over age 50; and 25% are over age 55. The Company understands this aging trend increases its health care costs and has implemented a number of plan changes and programs discussed below to manage and control its rising health care costs." 8 TR 1463.

Additionally, health care costs are increasing due to the national health care reform and the State of Michigan's Michigan Health Insurance Claims Assessment. 8 TR 1464. To help mitigate cost increases, the Company has implemented a number of plan changes. These changes include more cost sharing with participants, education regarding the prudent and informed use of health care benefits as well as the promotion of preventive services, the new Healthy Living Plan that is designed to provide preferred coverage to participants that take steps toward healthier lifestyles to lower overall health costs, and offering a Consumer-Directed Health Plan with a Company contribution available to the employee's health savings account.

8 TR 1463-1476, 1478-1480. With these cost saving measures, Mr. Kops testified that the Company believes that it can hold its annual health care increase to 6%. 8 TR 1465. The projected health care expenses for active employees are based upon actual costs for these benefits that have been incurred or are expected to be incurred. 8 TR 1461. The expenses for retirees are determined using actuarial analysis in accordance with ASC 715. 8 TR 1461. Retiree Health Care and Life Insurance costs have decreased over the past several years and are projected to further decrease during the test year. 8 TR 1481-1483.

Staff witness Nichols reviewed the Company's electric O&M expense for employee benefits and recommended an employee benefit expense of $74,741,000 for the projected test year. See Exhibit S-3, Schedule C5; Exhibit S-11.9. This recommendation includes expenses related to the Pension Plan, DCCP, 401(k) Savings Plan, Active Health Care/Insurance/LTD, and Retiree Health Care and Life Insurance benefits. The Company has accepted this expense amount as reasonable.

(ii) Areas of Dispute with Staff and the Attorney General

Consumers Energy requests that the Commission reject the Staff's and Attorney General's proposed disallowance of expenses related to DB SERP and DC SERP. These benefits are necessary to attract, retain, and motivate management personnel in the Company whose goal is to provide excellent, cost effective energy and service to customers, while optimizing the Company's resources to meet present day demands and future needs of the business and its customers. 8 TR 1486. A productive highly motivated workforce will always be to the benefit of customers. Mr. Kops presents multiple reasons supporting inclusion of these expenses and rejection of disallowances proposed by the Staff and Attorney General. 8 TR 1486-1489.

Management personnel make decisions throughout the Company that directly impact customers. Decisions on items such as operations, workforce, and expenses levels have a bearing on customer service and the customer's bill. As an example, Mr. Kops discussed the impact management decisions have had on the Employee Benefit plans. He indicated that:

> "executives have made many employee and retiree benefits-related decisions over the years which are outlined throughout my direct testimony in this case. Key decisions by these executives included the incorporation of health and wellness initiatives in the health care plans to drive and support a highly motivated and productive workforce serving customers and to contain future health care expenses. The Company changed from providing an expense-volatile Defined Benefit Pension Plan to a known-expense DCCP, which has helped customers save money on their bills over the years. More recently, changes made by these executives to retiree health prescription drug coverage and premium contributions have saved customers significant expense. In fact, these recent retiree health care changes have led the Company to request no recovery of retiree health care and life insurance expense in this case and the Company has actually significantly reduced its overall benefits expense recovery request, saving customers additional expense due to benefits cost." 8 TR 1486-1487.

Management's efforts to reduce the cost of benefits will reduce the costs incurred by the Company. This directly benefits customers by lowering the expense level included in rates.

Staff indicated that it was recommending exclusion of these costs because they were not included in prior decisions of the Commission. This does not present a valid basis to exclude these costs in the current case. The evidence presented by the Company in the current case supports a conclusion that these are reasonable expenses properly recoverable from customers. 8 TR 1488.

Further, a review of the Commission's past decision on DB SERP demonstrates a misperception of this benefit as being an incentive that did not show a benefit to the Company's customers. See MPSC Case No. U-14347, Opinion and Order, December 22, 2005, pp 34-35.

However, these (i) are not incentives but rather benefits similar to other recoverable benefits; and (ii) directly benefit customers. Retaining competent and motivated executives will benefit customers. Consumers Energy's demonstrated financial strength and the ability to attract capital is an essential requirement for providing competitive energy and services to its customers. 8 TR 1488. Additionally, management covered by these DB SERP and DC SERP plans are directly responsible for the day-to-day operation of the utility and meeting the diverse and demanding needs of customers. These plans provide a competitive benefit for management personnel who focus on a number of operational areas important to the customer including safety, system reliability, improved productivity, competitive pricing, quality, and customer service. 8 TR 1488.

Attorney General witness Coppola additionally argued that SERP benefit costs should be disallowed because the IRC placed limitations on funding additional benefits within a qualified plan. 10 TR 2301-2302. However, as Mr. Kops testified, "The value of these plans as a restoration of benefits truncated by Internal Revenue Service-imposed limits and as an individual incentive to the executive to maximize personal performance has proven worth across many industries, including the utility industry." 8 TR 1489.

The record evidence supports a conclusion that DB SERP and DC SERP benefit plans are a competitive and reasonable cost of business in the industry and necessary to attract, retain, and motivate executives to meet the needs of customers. Recovery of the DB SERP and DC SERP benefit plan costs by ratepayers is reasonable and appropriate, and the Commission should approve these expenses in rates.

f. Employee Incentive Compensation Plan ("EICP")

Consumers Energy is requesting recovery for the test year costs of its annual EICP incentives and the long-term incentive (restricted stock) plan. As explained below, the Commission should approve this portion of the Company's overall employee compensation package because it is a reasonable component of the Company's market-based overall compensation, and because it creates beneficial incentives for employees to improve performance and achieve targeted performance goals which benefit customers.

(i) Consumers Energy's Overall Employee Compensation Philosophy and Structure Is Reasonable

Consumers Energy witness Amy M. Conrad, the Company's Director of Compensation, provided testimony and exhibits explaining the Company's overall employee compensation philosophy and structure, and which supports recovery of the incentive portion of the package of compensation provided to non-union Company employees.[17] See, generally, 7 TR 1140-1198. Ms. Conrad testified that the Company's compensation philosophy is to pay employees a fair and reasonable salary, comparable to the market that is equitable to employees, which is consistent with the Company's values and strategies, and which supports and incents the highest level of customer service at a reasonable cost. 7 TR 1147. Ms. Conrad explained that the Company structures non-officer compensation for salaried employees by first determining, through a rigorous market survey process which uses valid and reliable data from multiple sources, the level of competitive pay necessary to attract and retain qualified employees. 7 TR 1143, 1149-1150. The Company actively monitors compensation levels to ensure that employees are neither overpaid nor underpaid relative to the market, and engages in a rigorous benchmarking

[17]Employees who are rated as "under-contributing" on their annual performance appraisal are not eligible for incentive compensation. 7 TR 1145.

analysis of comparable jobs and rates of pay. 7 TR 1149, 1151-1152. The Company's process of researching market pay data ensures that the Company's compensation levels match the relevant market, and are not inflated over prevailing market levels. 7 TR 1152. This overall market-based, competitive level of pay is then allocated between (1) base salary and (2) incentive compensation. The incentive compensation is part of the overall market-based competitive compensation, it is not an addition. 7 TR 1143-1144. The total compensation (base pay plus incentive compensation) is targeted at approximately the market median (50^{th} percentile). 7 TR 1144.

The Company's officer compensation levels are determined by the Compensation Committees of the Boards of Directors of Consumers Energy and CMS Energy. Ms. Conrad explained that the compensation package for officers includes: (1) base salary, (2) short-term (annual) incentive compensation, and (3) long-term incentive compensation, which are in total targeted at the median (50^{th} percentile) of the competitive market based pay. If any of these components was eliminated, one or both of the other components would need to be increased to remain competitive. 7 TR 1148. In determining individual officer compensation levels, the Boards of Directors' Compensation Committees are advised by an independent consultant and consider market research, experience levels, and individual contributions. 7 TR 1144, 1157-1159. The Company's requested recovery in this proceeding does not include the costs of the incentive compensation for the top six officers as identified by the 2014 Securities and Exchange Commission ("SEC") proxy filing. 7 TR 1144.

Ms. Conrad testified that the Company's overall compensation levels, including the officer and non-officer incentive compensation, are reasonable compared to the market, and that compensation without the incentive compensation is below market pay. 7 TR 1145. Ms. Conrad

noted that paying uncompetitive levels of pay would result in a lower qualified workforce. 7 TR 1145. Ms. Conrad also explained that the use of incentive pay structures is recognized as reasonable in the utility industry, stating:

> "[I]ncentive pay is the number one design used to influence short- to mid-term business results. Incentive mechanisms help communicate priorities, engage the employees in business success, reward valued skills and behaviors, and create business understanding for employees. Consumers Energy's incentive programs are structured in a way that is designed to help keep non-officers and officers focused on such areas as safety, reliability, and customer value. The incentive compensation program encourages employees to delivery their best performance for the Company's customers." 7 TR 1145.

See also 7 TR 1153-1154 for a survey of the substantial research which supports the conclusion that incentive compensation programs are consistently used in the utility industry.

Ms. Conrad explained that the Company's incentive compensation structure is supported by substantial and significant research, testifying as follows:

> "A wide body of research supports the view that variable pay works. One researcher states, 'theory and research show that incentive pay can substantially increase individual and organizational performance, and can represent a powerful tool for establishing a competitive advantage within an industry,' (Dow Scott, 'Incentive Pay: Creating a Competitive Advantage' – World-at-Work Press, 2007). I agree with this assessment. When properly selected and implemented, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. When goals are challenging yet achievable, employees are motivated to increase productivity. In addition, incentives increase a company's ability to attract, hire, and retain qualified and motivated individuals. A study by the International Society of Performance Improvement showed that incentive pay programs increase performance by an average of 22.0 percent. (International Society of Performance Improvement, 'Incentives Motivation and Workplace Performance Research and Best Practices' Spring 2002). As stated by the Society of Human Resource Management:

> 'Research has demonstrated that some human resource programs and initiatives produce a significant impact on performance in organizations (as measured by factors such as quality, productivity, speed, customer satisfaction and unwanted turnover). The two initiatives that consistently showed statistically significant positive results were linking pay to performance and using variable pay. Research has established the potential of variable pay to produce the desired business results' (Robert Greene, Variable Pay: How to Manage it Effectively, Society of Human Resource Management, April 2003). 7 TR 1148-1149."

Consumers Energy's practice of making a portion of overall employee compensation subject to incentives is consistent with best industry practices. 7 TR 1154.

As further explained below, the Company's incentive compensation plans are designed to emphasize and promote operational and performance objectives in four areas which are critical to the Company's utility service. Focusing employees on those goals provide qualitative and quantitative benefits for the Company's customers. With incentive compensation, the employees and the Company as a whole must re-earn the at-risk incentive compensation each year. If the targeted high levels of performance are not achieved, employees' incentive pay is reduced or eliminated. 7 TR 1156-1157. Customers benefit from incentive pay because the elimination of the variable at-risk incentive pay would mean that all compensation would be guaranteed and an important incentive to improve service would be eliminated. This result would be harmful to customers.

(ii) Structure of Consumers Energy's Incentive Compensation Plans

Consumers Energy's incentive pay structure includes a short-term incentive plan, called the EICP, and a long-term incentive plan, which is a restricted stock plan. The short-term EICP is designed to focus and reward achievement of performance goals over periods of

approximately one year or less. 7 TR 1144. Long-term incentive pay is designed to focus and reward performance over a period of longer than one year, and to reward good long-term decisions for the Company and its customers. 7 TR 1144. Consumers Energy's request for cost recovery in this proceeding includes $12.8 million test year expense for its incentive compensation plans, which is comprised of $5.3 million for EICP incentive compensation and $7.5 million for long-term incentive (restricted stock) compensation. 7 TR 1168; Exhibit A-26. Incentive compensation for the top six officers is not included in these requested amounts. 7 TR 1168.

The EICP incentive incorporates targets for: (1) safety, (2) reliability, (3) customer value, and (4) financial performance. 7 TR 1160. The EICP performance measures are summarized on Exhibit A-24.[18] The non-officer EICP equally weigh's the operational and performance measures of safety, reliability, and customer value with the financial measures:

> "- Half (50.0 percent) of employee's incentive will be based on achievement of operational and performance measures for safety, reliability, and customer value. (Currently there are 11 operational measures.)
>
> "- Half (50.0 percent) of employee's incentive will be based on the achievement of two financial measures, earnings per share ('EPS') and operating cash flow.[19] Consumers Energy is a vital part of the Michigan economy and it is important that the utility remain financially strong so that it can provide the utility service that customers expect and deserve. Financial health also leads to reduced costs of capital." 7 TR 1146.

[18] The EICP performance measures are aligned with Consumers Energy's "Growing Forward" strategy, which is based on management's view that, in order to achieve the Company's vision and purpose, the Company should focus on five key areas: (1) safe, excellent operations; (2) providing customer value; (3) effectively investing in utility assets for the benefit of customers; (4) positioning the Company to achieve fair and timely regulatory treatment; and (5) being financially healthy. 7 TR 1162.

[19] Ms. Conrad explained that the EPS and operating cash flow financial metrics, while related, are not duplicative. EPS is a measure of profit generated by a company's daily operations, and includes revenues and expenses. Some of the expenses used to calculate earnings are non-cash items such as depreciation and amortization, and do not impact cash flow. The incentive operating cash flow is a measure of cash generated from operations and what is needed to make investments in the utility. 7 TR 1166.

The officer EICP has the same goals, but the weightings are different. The safety, reliability, and customer value goals are a plus or minus modifier to the financial goals. 7 TR 1146. The EICP payout levels, also shown on Exhibit A-24, are established so that the threshold is at a level of achievement that can typically be met eight or nine times out of every ten years. 7 TR 1163. Maximum payout is for exceptional performance and is expected to be achieved one or two times every ten years. 7 TR 1163-1164.

The long-term incentive plan is an equity-based plan that uses the issuance of restricted stock with a three-year cycle period, and has two components: a performance component (75%) and a tenure component (25%). 7 TR 1146. The long-term incentive plan performance components are relative Total Shareholder Return ("TSR") and relative Earnings Per Share ("EPS") growth. Both are weighted equally (37.5%). 7 TR 1146. The relative TSR compares the shareholder returns of CMS Energy to the shareholder returns of the utilities in the S&P Midcap and in the S&P 500 indices. The relative EPS growth compares the EPS growth of CMS Energy to the EPS growth of the utilities in the S&P 400 Midcap and in the S&P indices. 7 TR 1146-1147. The performance component of the long-term incentive plan provides a head-to-head comparison of how well the Company has performed compared to other utilities and examines how the Company's long-term strategy is performing. 7 TR 1147.[20] The tenure component of the long-term incentive plan provides that the recipient employee receives the vested restricted stock upon remaining employed over a three-year cycle period. 7 TR 1147. The tenure component helps build executive share ownership, aligns shareholder and customer interests, and serves as an important retention mechanism. 7 TR 1147. Tenure-based restricted

[20] Ms. Conrad explained that the EPS measure in the annual EICP incentive is not duplicative of the EPS growth measure in the long-term incentive plan. The EPS measure in the EICP is an absolute measure over a short-term period (one-year), whereas the EPS growth measure is a relative measure compared to a group of peer companies over a long-term (three-year) period. 7 TR 1166

stock is awarded to non-officer members of the Board of Directors as part of their annual compensation, and performance-based and tenure-based restricted stock is awarded to officers and other key salaried employees to help attract, retain, motivate, and provide incentives for continued positive contributions to the success of the Company. 7 TR 1147.

(iii) Customers benefit from the Company's Incentive Compensation Plans.

Paying a competitive level of compensation is essential to Consumers Energy's ability to attract, retain, and motivate qualified employees. 7 TR 1170. As explained above, Consumers Energy's employee compensation is thoughtfully determined to ensure that it is reasonable and commensurate with comparable market-based salaries for similar positions. No evidence was presented in this proceeding which refutes this fact. The EICP and long-term incentive compensation plans are part of the overall reasonable level of employee compensation. 7 TR 1170. As a component of reasonable, market-based employee compensation, the incentive compensation costs are reasonable costs of doing business to provide utility service. Neither the EICP nor the long-term incentive plan is a bonus or profit-sharing mechanism. 7 TR 1176. The Company's incentive compensation plan is a part of the Company's overall reasonable compensation costs, and not in addition to them, like a bonus or profit-sharing plan would be. Consumers Energy's employees are not paid in excess of market rates when they receive incentive compensation. 7 TR 1176. Rather they are paid below market rates if they do not receive incentive compensation.

The Company's overall compensation costs are reasonable, including the incentive costs, and benefit customers. Customers benefit if the Company is able to attract, retain, and motivate its employees. All of the incentive plan costs could be included as part of reasonable, market-based pay. Overall levels of compensation are set at reasonable levels. There is no

reasonable basis to eliminate incentive compensation costs from the cost of service recovered in rates because they are a part of an incentive plan, rather than including the costs as part of base pay. 7 TR 1180. The costs of the incentive plans should be recovered in rates as part of the Company's reasonably incurred cost of providing utility service.

Shifting a portion of employees' reasonable, market-based compensation to an incentive based component benefits customers without additional cost. The incentive-based "carve-out" of the Company's reasonable costs of employee compensation puts a portion of employees' pay at risk unless the performance targets are achieved. 7 TR 1177. The Company's performance-based incentives provide concrete incentives to accomplish specific goals that represent performance priorities for Consumers Energy and its customers. 7 TR 1177. The incentive plans help create a culture of performance, rather than entitlement. 7 TR 1177.

Additionally, an incentive program structured to focus on safety, reliability, and customer value results in the following customer benefits:

- Safety measures result in reduced number of lost days (less absenteeism) and reduced medical costs;
- Reliability measures result in reduced interruption costs; and
- Customer value measures result in reduced operating and maintenance costs from increased productivity and quality. 7 TR 1177.

Customers also benefit from a financially sound utility. Customers benefit when the Company is able to raise capital, at the best available rates. Financial health leads to reduced costs of capital, and lower costs for customers. 7 TR 1178. In addition, customers benefit by having a portion of compensation structured in the form of equity-based, long-term incentive because there is no cash outflow as a result of providing that incentive. The equity-based, long-term incentive also results in tax savings which are passed on to customers, as stock grants

result in a tax deduction on the Company's corporate return. 7 TR 1178. The absence of a long-term incentive plan would require additional cash outflows in the form of salaries to pay competitive levels of compensation. This would result in fewer available funds for utility investment, thus directly impacting the Company's ability to provide customer value and reliability. 7 TR 1178. Long-term incentive participants are rewarded only if good long-term decisions are made. Strong stock and EPS growth performance in comparison with peer companies provides a reliable measure of a well-run, high performing utility. Strong stock performance also helps provide access to capital, which the Company uses to invest in plant that supports safe and reliable utility service, thus benefiting customers and the State of Michigan. 7 TR 1179.

The benefits provided to customers from the EICP and long-term incentive plans outweigh the costs of those plans. The qualitative benefits of the incentive plans are described above. In addition, Company witness R. Michael Stuart provided a quantitative analysis of the benefits of the incremental portion of reasonable market-based compensation that is incentive-based. Mr. Stuart testified that the design of the EICP leads to lower costs and improved service for the benefit of customers. 6 TR 913. Mr. Stuart explained that while it is not possible to specifically quantify the benefits for every metric included in the EICP, the Company has quantified the benefits associated with five of the metrics, which quantification is summarized as follows: (1) Employee safety: employee safety incidents decreased by 72% from 2006. The resulting reduction in lost work days and medical expenses provide approximately $2.2 million of annual savings which directly benefit customers. 6 TR 913-914. (2) Distribution reliability: Based on cost per outage minute estimates provided by the independent Berkeley Laboratories, Consumers Energy's seven-minute outage reduction in average outage minutes achieved since

2006 has resulted in annual savings to the Company's business customers in excess of $25 million. 6 TR 914. (3) Generation reliability: The Company improved in this area from an annual forced outage rate of 9% to an annual rate of 4%, which reduced fuel expenses by more than $4.6 million per year. 6 TR 914. (4) First time quality improvement: This metric was initiated in 2013. It is an equally-weighted index of process improvement measures across seven operating areas. The measures were established to quantify the Company's continuous process improvement efforts to reduce, rework, and eliminate waste. 6 TR 914. Annual improvement targets are established for each metric and for the index total. In the first year, the Company achieved a 24% improvement versus a 10% improvement target. 6 TR 914-915. This improvement resulted in savings to customers in excess of $1.4 million. 6 TR 914. (5) Productivity improvement: The Company improved its productivity by approximately 46% over the past seven years, which is a key reason the Company' O&M expenses compare very positively to its peers. The Company's productivity metric is based on the percent improvement across ten weighted department-level productivity metrics. 6 TR 915. During the seven-year period, Company employees per customer decreased at an average rate of 1.25% per year, which resulted in a savings to customers of $10.7 million. 6 TR 913-915.

The quantified benefits for five of the metrics included in the EICP described above greatly exceed the total costs of the incentive plans which are requested for recovery in this proceeding (the costs are $12.8 million for the test year, 7 TR 1179, Exhibit A-26). Mr. Stuart explained that electric customers' allocated portion of the quantified benefits associated with employee safety, quality, and productivity amounts to more than $9 million annually. 6 TR 916. When combined with the annual benefit of distribution ($25 million) and generation ($4.6 million), the total quantified annual benefit for electric customers is approximately

$38.6 million. 6 TR 916. These quantified benefits are in addition to the qualitative benefits of the incentive compensation plans which are described above. Mr. Stuart testified that the incentive compensation plans are a primary reason why the significant benefits identified above were achieved for customers. 6 TR 917. The benefits for customers far exceed the expense for the incentive compensation plans which are included for cost recovery in this proceeding. 6 TR 917.

(iv) The Commission should approve cost recovery for the Company's Incentive Compensation Plans

In Case No. U-14347, the Commission established a standard for recovery of incentive compensation plans. In its December 22, 2005 Order in that case (page 34), the Commission stated:

> "In Case Nos. U-10149 and U-10150, the Commission determined that executive bonus and employee incentive plans require a showing that the plan will not result in excessive rates and that the benefits to ratepayers from the bonus and incentive plans will, at a minimum, be commensurate with the programs' costs."

As an initial matter, Consumers Energy notes that this standard is not entirely applicable to the Company's incentive compensation plan costs included in this case because they are not associated with a "bonus" plan. The incentive compensation plans are part of the reasonable costs of market-based employee compensation and therefore should be included as part of the Company's cost of utility service.

Moreover, the Company's request for cost recovery of its incentive compensation plans meets the standard of proof articulated in Case No. U-14347. The costs of the incentive plans are reasonable components of the reasonable, market-based compensation package necessary for the Company to attract and retain a qualified workforce. 7 TR 1177. They are reasonable

components of the cost of providing utility service to customers, and will not result in excessive rates.

Consumers Energy submits that the Commission should focus its review on whether the overall level of compensation is reasonable, and not whether a component of the overall level of compensation is comprised of an incentive component which is at-risk for employees (i.e., they do not receive it unless they collectively achieve the targets associated with the incentive). Examining whether the overall level of compensation is reasonable provides a better indication of whether the incentive plan results in excess rates rather than attempting to examine the cost allocable to the incentive compensation compared to benefits to customers. The overall level of compensation Consumers Energy has included in this case is reasonable.

Consumers Energy believes a more appropriate standard for recovery of incentive employee compensation costs is the standard which was articulated by the Indiana Utility Regulatory Commission ("IURC") in a 2011 case involving Southern Indiana Gas and Electric Company's request to recover incentive compensation. In an Order issued April 27, 2011 in IURC Case No. 43839, the IURC stated at page 50:

> "The Commission recognizes the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified personnel. The criteria for the recovery of incentive compensation plan costs is [sic] well established. We will allow recovery in rates when: (1) the incentive compensation plan is not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs."

The IURC recognized the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified employees. Instead of requiring a

quantification of customer benefits specifically related to the metrics of the incentive plan, which can be extremely difficult for measures that support undeniably desirable achievements (e.g., improved customer satisfaction and safety), the Indiana criteria require there be a combination of operating and financial metrics and a demonstration that there is no resultant excess compensation. This is a reasonable approach.

Consumers Energy's incentive compensation plans meet these standards articulated by the IURC. Consumers Energy's EICP includes operational and performance goals in addition to financial goals. The financial goals are not disproportionately weighted in the metrics of the EICP, and the entire costs of the incentive plans are more than covered by the benefits which accrue to customers from the non-financial metrics described by Company witness Stuart, as explained above. There is no excessive pay because incentive costs are a carve-out, rather than an add-on, to the reasonable competitive market level of compensation. The benefits which accrue to customers as a result of achievement of the financial metrics[21] are in addition to the substantial, quantified benefits the non-financial targets provide, which substantially exceed the costs of the incentive plans. As explained in detail above, the incentive compensation plans do not result in excessive pay and are part of a reasonable employee compensation package. Further, Consumers Energy's shareholders are allocated a part of the Company's incentive compensation costs. Shareholders bear the incentive compensation costs in years when the actual payouts are greater than the target level included in this proceeding. In addition, the incentive compensation for the top six officers has not been included in the Company's requested recovery in this case. Further, cash payments under the EICP reduce earnings and grants of equity under the long-term incentive increase outstanding shares, which are both

[21] The use of earnings and cash flow measures in the EICP and officer annual incentive recognizes that the Company's financial health is important for the Company, it customers, and the State of Michigan. Financial health leads to reduced costs of capital, thus providing savings to the customer. 7 TR 1178.

reductions in value to shareholders. 7 TR 1175. Although the Company does not believe the IURC's third criterion of shareholder burden should be included in the Commission's analysis of cost recovery for the Company's incentive plans, the Company's plans nevertheless meet that standard.

Consumers Energy's incentive compensation plans also meet the criteria the MPSC used in Case No. U-14347, *supra*. The incentive plans do not result in excessive costs and provide benefits to customers. The measures used for the incentive plans are customer value, safety, reliability, and financial performance, all of which benefit customers, as explained in detail above. The Company presented evidence showing that the quantitative benefits of the incremental portion of employee compensation which is incentive-based well-exceed the total costs of the incentive compensation. In addition, there are qualitative benefits of the plans which also benefit customers. The compensation approach used by the Company is reasonable, consistent with industry practice and standards, and represents best practices for creating customer focus through compensation design, and does so without additional cost to the customer (because the incentive plans are part of the overall reasonable, market-based pay structure). 7 TR 1181. The overall compensation levels, including the incentive plans, are reasonable, and should be included in the Company's cost of service in this proceeding.

g. <u>SG/AMI O&M Expense</u>

Company witness Warriner explained the projected test year Electric and Common O&M AMI Expenses, which total $14,238,000. 6 TR 942-943; Exhibit A-75, line 5, column (e). This total amount is comprised of $9,345,000 for project management, systems and software O&M and SG infrastructure O&M; $3,607,000 for O&M associated with the purchase and installation of electric AMI meters; and $1,286,000 for costs associated with customer communication prior

to AMI meter installation, as well as costs associated with preparing employees to use the AMI functionality and support Smart Energy customers. Exhibit A-75; 6 TR 942-943. These O&M costs are reasonable and part of the AMI Program which, as explained above in Section III.A.4., provides benefits to customers, and should be approved.

h. Uncollectible Expense

(i) Company's Position

Company witness Harry testified concerning the Company's Uncollectible Accounts expense. According to Mr. Harry, Uncollectible Accounts expense is made up of: (1) the write-off of customer accounts receivable balances that are deemed uncollectible; and (2) changes during the period in the uncollectible reserve account. 6 TR 648. The Company estimates the Uncollectible Accounts expense for the test year at $30.799 million. 6 TR 648; A 32 (DLH-4).

To calculate uncollectible accounts the Company first began with total Uncollectible Accounts expense and subtracted amounts associated with the uncollectible tracker expense and PeopleCare to arrive at net Uncollectible Accounts expense.[22] 6 TR 648. The amounts recovered through the Uncollectible Expense Tracking Mechanism ("UETM") were not included when calculating the uncollectible expense for 2011 and 2012. 6 TR 648-649. The amounts related to PeopleCare are excluded because those amounts are considered a donation. 6 TR 649. The test year Uncollectible Accounts expense is based on a three-year average Bad Debt Loss Ratio ("BDLR") of net Uncollectible Accounts expense to electric service revenue for the years 2011-2013 as shown on Exhibit A-32 (DLH-4). 6 TR 649. This ratio is applied to

[22] The Commission adopted an Uncollectible Expense Tracking Mechanism in the November 2, 2009, Order in Case No. U-15645 which was subsequently terminated as of November 30, 2010, in Case No. U-16191. 6 TR 648.

test year electric service revenue plus surcharge revenue to arrive at test year Uncollectible Accounts expense on line 7 of Exhibit A-32 (DLH-4). 6 TR 649.

(ii) Areas of Dispute with Staff

Staff's proposed amount of Uncollectible Accounts expense should be rejected as it does not provide a reasonable projection of this expense. Staff's Uncollectible Accounts expense recommendation appears to be based exclusively on budget data and fails to provide any economic, revenue, or customer assumptions or a calculation methodology to validate the reasonableness of the projection. 6 TR 658. It is not tied to revenue requirements in this case or current conditions.

Company witness Harry explained that the Company's methodology provides a more reasonable and comprehensive projection of Uncollectible Accounts expense. 6 TR 659. The Company's test year Uncollectible Accounts expense is based on a three-year average BDLR of Uncollectible Accounts expense to electric service revenue for the years 2011 through 2013. 6 TR 659. This ratio is applied to the test year electric service revenue plus Energy Optimization surcharge revenue to arrive at test year Uncollectible Accounts expense. 6 TR 659.

Moreover, test year electric Uncollectible Accounts expense is largely impacted by the economy as well as fuel and purchased power cost prices. 6 TR 659. These factors tend to fluctuate over time as reflected in Uncollectible Accounts expense over the 2011 through 2013 timeframe as shown in the trend of energy Uncollectible Accounts expense for those years ($32.2 million, $23.2 million, and $32.6 million, respectively). 6 TR 659. The averaging of past expenses to determine a projected expense amount can be appropriate in instances when the expense for previous years are relatively consistent or go both up and down, creating some

likelihood that the future period's activity will be similar to the average of the past periods. 6 TR 659.

As Staff's Uncollectible Accounts expense projection fails to encompass the comprehensive analysis embodied by the Company's projection, Staff's recommendation should be rejected. The Company's methodology and projections are reasonable and should be used in this case.

(iii) Areas of Dispute with the Attorney General

Consumers Energy requests the Commission to reject Attorney General witness Coppola's recommended Uncollectible Accounts expense of $25.3 million. 10 TR 2288. His projection was based on a five-year average of the ratio of net charge offs to revenue for the period 2010 through 2014, which does not improve the estimate of uncollectible expense over the Company's three-year average approach. 6 TR 660. To the contrary, it makes it less reliable. Company witness Harry explained that by using a five-year average approach, Mr. Coppola's calculation dilutes the recent trend of higher uncollectible expense by incorporating a lower 2010 historical year resulting in a lower ratio of net charge offs to revenue and a lower projection of Uncollectible Accounts expense. 6 TR 660. On the other hand, the Company's projection at $30.8 million is more reflective of the Company's recent uncollectible expense experience over the 2012 through 2014 timeframe, as shown in the trend of Uncollectible Accounts expense for those years ($23.2 million, $32.6 million, and $32.4 million, respectively). 6 TR 660.

Mr. Coppola's recommendation does not result in a reasonable projection of Uncollectible Accounts expense and, thus, should be rejected by the Commission.

i. Injuries and Damages Expense

The Commission should reject the Staff's $684,000 increase to the Company's injuries and damages expense. Exhibit S-3, Schedule C5. Staff witness Nichols' projection of injuries and damages expense unreasonably relies on budget data without any historical analysis of this expense. 6 TR 661. Company witness Harry explained that the Company's projection in this case is shown in Exhibit A-33 (DLH-5) and is based on a five-year average of the historical years 2009 through 2013. This five-year average provides a reasonable estimate for this expense due to the potential variability of expense levels in this expense category. 6 TR 661. Injuries and damages expense levels are largely determined by the number and magnitude of claims experienced in any given year. 6 TR 661. As a result, a historical averaging approach to develop a projection provides a more reasonable and supportable estimate of future injuries and damages expense than the Staff's approach.

D. Depreciation and Amortization Expense

In its initial filing, the Company used the Commission approved depreciation rates from the Case No. U-16054 settlement, along with the projected capital expenditures and assumed plant retirements, in the determination of the depreciation expense adjustment necessary to arrive at an appropriate level of book depreciation expense. 5 TR 326. Book depreciation expense was developed by applying the functional composite book depreciation rates to the average projected test year depreciable plant balances. 5 TR 326. The adjustment on line 24 of Exhibit A-8 (NNB-62), Schedule C14, increases depreciation expense from the historical period due to significant new investment combined with the higher book rates resulting from the Case No. U-16054 settlement. 5 TR 326.

However, in its filing in this case, the Company also indicated that if a final order in the Company's pending Electric & Common Plant Depreciation case, Case No. U-17653, was issued

before a final order is issued in this proceeding, the depreciation rates approved in Case No. U-17653 would be utilized in the final rates determined by this proceeding. On May 14, 2015, the Commission approved a Settlement Agreement in Case No. U-17653 that revises depreciation rates for electric and common utility plant. 5 TR 339. The Commission's Order in Case No. U-17653 indicated that, as provided by the Settlement Agreement, the new depreciation rates would become effective with the final order in Consumers Energy's next general electric rate case. 5 TR 339. Case No. U-17735 is Consumers Energy's next general electric rate case and therefore, the new depreciation rates will result in an increase in annual depreciation expense effective with the final order in this current case. 5 TR 339-340.

In order to capture the appropriate level of depreciation expense to include in rates when the new depreciation rates go into effect with the final order in this case, a separate calculation of depreciation expense was necessary. 5 TR 340. The separate calculation of $515,949,000 expense, represents a full 12-month calendar year of expense using the new depreciation rates from the Case No. U-17653 Depreciation Case Settlement. 5 TR 340. However, due to the fact that the Company has reflected a separate revenue requirement for the Jackson Gas Plant, the depreciation expense attributable to the Jackson Gas Plant should be removed from this amount resulting in a test year depreciation expense of $511,130,000. See, Exhibit A-79 (NNB-69), line 7, column (c). Company witness Busack explained that this is the appropriate level of expense to be included in the Company's revenue requirement calculation. 5 TR 340. After also taking into consideration the adjustments for accumulated depreciation, the new depreciation rates result in approximately $33,461,000 additional jurisdictional depreciation expense as shown on Exhibit A-77 (NNB-67), column d, line 12. Exhibits A-78 (NNB-68) and Exhibit A-79 (NNB-69)

provide the adjusted rate base and adjusted net operating income which support Exhibit A-77 (NNB-67).

Staff's level of depreciation expense should be rejected. Staff's calculation of depreciation expense, as provided by Mr. Gerken (9 TR 1954-1955), utilizes depreciations rates set in Case No. U-16054 and understates the depreciation expense that will occur during the time rates established by a final order in this case will be in effect. 5 TR 339. If Staff's lower level of depreciation expense is used in setting rates, the Company will be unreasonably required to recover depreciation expense at a much lower level than the expense being recognized on the books. 5 TR 341. The Company's re-calculation of depreciation expense, as explained above, ensures that Company's rates will be set in order to recover the appropriate level of depreciation being expensed on the Company's books. 5 TR 341.

E. Taxes

1. Property Tax

Brian J. VanBlarcum, Property Tax Manager in the Company's Corporate Tax Department, testified on behalf of the Company concerning property tax. Mr. VanBlarcum testified that the test period property tax expense is projected to be $158.6 million. 8 TR 1579. Mr. VanBlarcum set forth the methodology he used to reach that projection in his testimony, see, 8 TR 1576-1579; Exhibit A-68 (BJV-1). No party contested Mr. VanBlarcum's calculation of the Company's property tax expense.

2. Federal, Michigan, and Local Income Taxes

Staff witness Nichols' projected Federal, Michigan, and Local Income Tax amounts should be rejected. These amounts rely on incorrect adjustments to depreciation rates, Other O&M, and projected revenue which have been addressed by the Company throughout this Brief.

Company witness Busack presented the Company's projected General Taxes, projected Federal Income Taxes, projected State Income Taxes, and projected Other (or Local) Taxes. 5 TR 322. As a result of new depreciation rates approved in Case No. U-17653, which go into effect at the conclusion of this proceeding, and the Company's adoption of certain Staff Other O&M projections, the Company projects Property and Other Taxes expense in the amount of $182,344,000; Local and State Income Tax expense in the amount of $34,619,000; and Federal Income Tax expense in the amount of $116,389,000. Appendix C, page 1, lines 5-7, column (d).

F. AFUDC

The criteria for applying AFUDC to a construction project requires on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. 5 TR 327. Consumers Energy has calculated a test year jurisdictional AFUDC level of $4,327,000. See Exhibits A-8 (NNB-59), Schedule C11 and A-8 (NNB-49), Schedule C1. No party presented any adjustments to AFUDC; however, Staff did calculate a $1,000 decrease to AFUDC based on Staff's jurisdictional factor as determined in its Cost of Service Study ("COSS"). See Exhibit S-3, Schedule C1, line 12, column (d).

G. Calculation of Adjusted Net Operating Income

Total revenues of the Company are $4.204 billion, as shown in Appendix C, p. 1. After expenses, net operating income is $462.063 million. Adjusting for AFUDC leaves an adjusted net operating income of $466.390 million. Appendix C, p. 1. Staff's adjusted net operating income is calculated at $528.095 million. Appendix C.

VI. OTHER REVENUE AND ACCOUNTING ISSUES

A. Revenue Adjustment Mechanism

Company witness Laura M. Collins, a Senior Rate Analyst in the Pricing section of the Rates Department, presented the Company's proposed Revenue Adjustment Mechanism.

5 TR 562-567. The Company is proposing this mechanism because sales and associated revenues are difficult to predict and are highly volatile due to economic conditions, electric choice migration, and weather. 5 TR 562. The Revenue Adjustment Mechanism will ensure the ability to consistently collect the level of revenues – no more and no less – authorized by the Commission. 5 TR 563. The Company has made its request conditional on the enactment of legislation addressing revenue adjustment mechanisms for electric utilities during the pendency of this case. 5 TR 563.

Ms. Collins provided a detailed description of the Company's proposed Revenue Adjustment Mechanism as follows:

> "Q. Please describe the Revenue Adjustment Mechanism being proposed in this case.
>
> "A. The Company is proposing a symmetrical Revenue Adjustment Mechanism that compares the nonfuel rate revenues approved by the Commission in the most recent proceeding to the nonfuel revenue generated through actual sales for the period of time under evaluation. This comparison will be performed by rate class. The Company proposes to compare actual total delivery revenues (less customer charges) to the approved rate case delivery revenues (less customer charges), which would apply to all customers, and to compare actual nonfuel power supply revenues to the approved power supply revenues, which would apply only to Full Service customers. The difference in revenues would be deferred on the Company's books, pending an annual reconciliation process. The Company proposes that the revenues be reconciled on an annual basis, beginning with the end of test-year period in this case. If the Company collects more total delivery or total nonfuel power supply revenue during the 12-month period than was authorized by the Commission in this electric rate case, then following Commission review and approval, the Company would refund the amount of the over-collection to its customers on a prospective basis. Over-collected delivery revenues would be refunded to all customers, while the amount of over-collected nonfuel power supply revenues would be refunded to Full Service customers. If the

> Company did not collect its level of authorized delivery or nonfuel power supply revenues, then following Commission review and approval, the Company would collect the shortfall with approval of the Commission on a prospective basis." 5 TR 563-564.

Ms. Collins also extensively addressed the reconciliation procedures for the proposed Revenue Adjustment Mechanism. 5 TR 564-566. Reconciliation proceedings will be filed within 90 days of the annual effective period that the mechanism operates and be conducted on a 270-day schedule to ensure compliance with GAAP Rule ASC 980-605-25.[23] 5 TR 564-566. The Company also proposes to use actual revenues rather than weather-normalized revenues during the reconciliation process, as illustrated by Exhibit A-22 (LMC-12), to determine if the Company's over- or under-collected delivery or nonfuel power supply revenues. Further, the Company does not propose any limitations on the amount of revenue that would flow through the Revenue Adjustment Mechanism and proposes that the mechanism operate until the Company self-implements new electric rates in conjunction with its next electric rate case. 5 TR 566.

The Company's Revenue Adjustment Mechanism was supported by NRDC witness Ralph Cavanaugh; however, various parties opposed or criticized the Company's proposal. Staff witness Nicholas M. Revere proposed a cap for the Revenue Adjustment Mechanism such that the qualifying revenue shortfall be capped at 1.5% of rate case qualifying revenue for the first annual reconciliation and raised to 3% for each annual reconciliation thereafter. 9 TR 1852. Mr. Revere further suggests that the revenue used in the reconciliation be weather normalized.

[23] GAAP Rule ASC 980-605-25, requires the Company to collect additional revenues within 24 months following the end of the annual period in which they are recognized. 5 TR 565. A 270-day schedule, from the date of the Company's reconciliation filing, will enable the Company to comply with ASC 980-605-25 by ensuring that all revenues are reconciled within 24 months of being realized. 5 TR 565-566.

5 TR 572. The recommendations produce unreasonable results and should be rejected by the Commission.

First, a cap is not necessary with the Company's proposed Revenue Adjustment Mechanism. The Revenue Adjustment Mechanism is designed to collect no more and no less than the amount of nonfuel revenue authorized by the Commission. 5 TR 571. Thus, imposing a cap on the mechanism would unreasonably restrict the Company from consistently collecting its revenue and defeats the purpose of the mechanism. 5 TR 571.

Second, the practice of weather-normalizing revenue subjects customers, and the Company, to unnecessary risks and results in a flawed decoupling mechanism. 5 TR 572. In his direct testimony, NRDC witness Cavanaugh accurately assessed the risks of weather normalization in the reconciliation process as follows:

> "Weather normalizing means that Consumers' customers are exposed to unnecessary risks associated with the higher than anticipated utility bills that typically accompany extreme weather conditions; under the approach that Consumers proposes, customers will receive refunds under such conditions, and will only face (modest) weather-related surcharges when mild weather reduces utility bills." 10 TR 2482.

The Company's proposal is reasonable and should be adopted.

B. IRM

1. Company's Position

Consumers Energy is requesting the Commission authorize an IRM. 5 TR 328-336. Company witness Busack explained that the IRM provides for recovery of the 2017 and 2018 average incremental rate base and the associated direct expenses beyond the level ultimately approved in test year. 3 TR 329; Exhibit A-14 (NNB-65). The IRM calculates the incremental revenue requirement associated with recovery of these incremental investment amounts and will operate through a surcharge that is effective June 1, 2016 until rates are reset in a subsequent rate

case. 3 TR 329. Following the end of 2017, the Company will file the first of two contested reconciliations which update the initial incremental revenue requirement calculation with actual balances and determine if the actual incremental rate base is greater or less than projected amounts reflected in the surcharge rates. 3 TR 329. The IRM surcharge would be reduced to incorporate any decrease to the incremental revenue requirement. 3 TR 329.

Company witness Busack presented extensive testimony which explains the calculation of the IRM incremental revenue requirement. 5 TR 330-333. Exhibit A-14 (NNB-65) calculates the incremental rate base arising from the 2017 and 2018 projected capital expenditures and corresponding incremental revenue requirement. 5 TR 329. The incremental revenue requirement from the 2017 and 2018 incremental rate base equals the sum of: (1) the incremental return on rate base; (2) the incremental depreciation expense; (3) the incremental property tax; and (4) the incremental AFUDC offset amount. 5 TR 329. The incremental revenue requirement is based on capital expenditures supported by Company witnesses Kehoe, Palkovich, Warriner, and Varvatos in this case. 5 TR 330. However, if the Commission were to adopt different amounts in its final order in this case, then the incremental revenue requirement should be calculated using the amounts adopted by the Commission in its final order.

The first of two annual reconciliations, illustrated by Exhibit A-15 (NNB-66), for the Company's IRM would be filed on May 31, 2018. 5 TR 334. This proceeding would be limited to a comparison between incremental rate base reflected in surcharge rates compared to actual incremental rate base, at an aggregate level, and would utilize the Company's 2017 Form P-521 filing to determine the actual 2017 electric net plant ending balances. 5 TR 334-335. Ms. Busack provided additional detail regarding how the reconciliation process would address

future rate base that is less than or greater than the amount approved in final rates in this proceeding as follows:

> "Q. What does the Company propose if the reconciliation determines incremental 2017 rate base is less than the amount approved in final rates?
>
> "A. In the event that a given year's incremental rate base is less than the amount approved by the Commission in this case, the Company will calculate the return on rate base, the depreciation expense, property tax, and the AFUDC offset on the deficiency using the same methodology used to calculate the projected incremental revenue requirement. The calculation will apply the same factors for return on incremental rate base, incremental depreciation expense, incremental property taxes, and the incremental AFUDC offset to the rate base as originally used to develop the incremental revenue requirement amount. This excess revenue requirement would be the amount used to adjust the future IRM surcharge."
>
> ***
>
> "Q. How will the Company's IRM proposal work if incremental capital expenditures are higher than amounts approved in final rates?
>
> "A. The Company does not propose collecting any additional revenue from customers when the incremental capital expenditures are higher than the amounts approved for collection in the IRM." 5 TR 334-335.

In the event that projected 2017 and 2018 incremental rate base is determined to be greater than the actual amount, the IRM surcharge would be reduced consistent with the amount of investment difference. 5 TR 335. Further, if the surcharge is in effect for a partial year due to new rates being implemented in a subsequent general rate case, the reconciliation filing's determination would be pro-rated to the period the surcharges were in effect based on the percentage of billed sales versus annual sales volumes within the applicable year.

Exhibit A-23 (LMC-13) provides the rates that incorporate additional capital spending for 2017 and 2018 associated with the Company's proposed IRM. 5 TR 567. The Company is proposing to collect the incremental revenue through demand and energy surcharges for each rate schedule. 5 TR 567. Moreover, surcharges associated with production capital expenditures would apply to only Full Service customers, while distribution capital expenditures would apply to both Full Service and ROA customers. 5 TR 567. The rates, as illustrated in Exhibit A-23 (LMC-13) would be effective for service rendered on and after June 1, 2016. The June 1, 2017 surcharges also included in that exhibit would be added to the June 1, 2016 surcharges and those surcharges would continue until rates were modified in the Company's next electric rate case. 5 TR 568.

2. Areas of Dispute with Various Intervening Parties

Staff, Energy Michigan, the Attorney General, Hemlock Semiconductor Corporation ("HSC"), ABATE, The Kroger Co. ("Kroger"), and Wal-Mart criticized the Company's IRM proposal. The two general assertions at the core of these criticisms are: (1) that the IRM does not provide for an adequate prudency review and (2) that the IRM shifts risks to customers. These concerns are unfounded and should be rejected by the Commission.

The Company's IRM proposal includes the opportunity for more reviews and Staff audits than capital expenditures that are approved through traditional ratemaking. 5 TR 344. Company witness Busack explained that the Company's proposed capital expenditures for the remainder of 2016, 2017, and 2018, as identified by Company witnesses Kehoe, Palkovich, Warriner, and Varvatos in this case, are subjected to the same level of review in this case as all other proposed test year capital expenditures. 5 TR 344. Additionally, as comprehensively explained in the section above, and in the Company's testimony and exhibits, the remainder of 2016, 2017, and

2018 capital expenditures are subject to a second review in the IRM reconciliation case that is not afforded to capital expenditures that are not subject to the IRM. 5 TR 344.

Criticisms about commitment to spending also lack merit. First, as noted above, the Company's proposal includes annual contested reconciliation cases which will review actual investments compared to capital expenditure amounts projected in the IRM surcharges. 5 TR 334-335; 5 TR 344. Further, the Company must maintain the flexibility to respond to market forces as well as future safety and reliability concerns and maintain the ability to run its business and not be tied to individual, strictly defined spending plans. 5 TR 344-345.

The Company's proposed IRM will not unfairly shift risks to ratepayers. The IRM actually reduces the risk that customer rates will reflect costs related to investments that did not ultimately come to fruition or provide a benefit. 5 TR 345. In contrast, general rate cases, without an IRM mechanism, establish rates based on a projected test year revenue requirement and provide no post-test year reconciliation of costs. 5 TR 345. The IRM reconciliation process will more closely align projected investment with actually incurred costs and thereby reduce regulatory lag and ratepayer risk. 5 TR 345.

HSC witness Michael P. Gorman also inaccurately claims that the Company's IRM will increase deferred taxes which can increase zero cost of capital available to support the Company's revenue requirement. 10 TR 2244. Ms. Busack explained that while deferred taxes may increase, the deferred tax portion as a percent of the capital structure may not be higher. 5 TR 347. Ms. Busack further explained that long-term debt and common equity may increase as well to fund future investments and that the deferred tax portion of the capital structure may be higher, lower, or the same. 5 TR 347. It is not appropriate to view any single piece of the Company's capital structure in isolation. 5 TR 347. The Company is using the capital structure,

as proposed in this case, as a reasonable estimate for the time period the IRM will be in place. 5 TR 347.

Thus, for the reasons stated above, the various criticisms of the Company's IRM should be rejected by the Commission. The Company's proposed IRM is reasonable.

C. Accounting Requests

Company witness Harry also presented two requests for accounting approval which were unopposed by the parties to this case. 6 TR 653-656. The Company's first request relates to the Company's proposed Revenue Adjustment Mechanism. Specifically, since the Revenue Adjustment Mechanism would result in deferred debits or credits until any under-recovery or over-recovery is fully collected or refunded, the Company requests approval to recognize regulatory assets or liabilities as needed to record these deferred amounts. 6 TR 653. Further, any outstanding regulatory asset or liability associated with this mechanism would accrue interest at the Company's short-term borrowing rate. 6 TR 653.

Next, the Company requests an accounting adjustment related to the Saginaw Service Center ("SSC"). 6 TR 654. The Company requests the SSC Account 114 amortization expense be recorded in Account 406, Amortization of Electric Plant Acquisition Adjustments, for the purpose of providing for the extinguishment of the amount in Account 114. 6 TR 654. The Company also requests a 15-year amortization life. 6 TR 654. The total amount of SSC Account 114 adjustment is $1,954,017, and the recovery of these costs, as amortization expense, should be applied to all jurisdictional customers' base rates. 6 TR 654.

D. Line Loss Issues

Company witness Palkovich sponsored the Company's original 2013 Line Loss Study. See Exhibit A-56 (MPP-6). The Line Loss Study was prepared to determine the line losses, or

total energy lost, associated with the various components on the Company's electric distribution system. 8 TR 1380. The 2013 Line Loss Study allocates system energy and demand losses among the various components of the system by calculating a percentage loss factor for each component. 8 TR 1343, 1372; see also Exhibit A-56 (MPP-6).

In response to a discovery question, the line loss factors originally shown in Exhibit A-56 (MPP-6) were updated. This updated Line Loss Study is shown on Exhibit A-116 (MPP-11) and was provided to all parties during discovery. 8 TR 1372. The same methodology was used to conduct both Line Loss Studies. 5 TR 492. The difference between the two studies is the use of data specific to Consumers Energy. Exhibit A-56 (MPP-6) utilized data for the entirety of the MISO foot print in its analysis; whereas, Exhibit A-116 (MPP-11), the updated study, utilized actual Consumers Energy pertinent data. 8 TR 1381. As Exhibit A-116 provides more accurate analysis of line loss on Consumers Energy's distribution system, the Company requests that the Commission utilize the updated Line Loss Study. 8 TR 1372.

The use of the updated Line Loss Study reflects only small changes to the existing line losses currently in rates. 5 TR 491. The impact of this change would result in an approximate $1 million aggregate reduction in revenue requirement for Residential and Secondary customers (5 TR 492), and would increase the revenue requirement for the Primary class by approximately $1 million. 5 TR 491-492. If the Commission adopts the updated Line Loss Study, this change should be included when re-running the COSS.

When reviewing whether a new line loss factor should be adopted, MEC/NRDC/CARE witness Jester argued that the Company should be "expected to demonstrate that it exercised appropriate diligence in ensuring that the combined costs of system losses and available mitigation measures have been or are being minimized." 10 TR 2366. Mr. Jester provided a list

of eight measures that the Company should examine in order to mitigate system losses. 10 TR 2366-2367. His proposals should not be adopted in this case.

Consumers Energy does consider line losses when evaluating its capital investments. 8 TR 1376. The Company's projected expenditures in its New Business, Reliability, Grid Modernization, Capacity, and Asset Relocation Programs provide opportunities for loss savings. 8 TR 1376. Additionally, the Company is planning on commencing a pilot program this summer that will collect the data that will allow the Company to evaluate the effect of different methods for reducing loss on the Company's distribution system. 8 TR 1398-1401; see also Exhibit MEC-45. While the Company is exploring options to reduce line loss, investments in projects cannot be economically justified based solely on loss savings projections. 8 TR 1377. Ms. Palkovich testified, "It would take significant additional investment above and beyond what is currently being requested in this rate case to make even a small reduction in the overall line-loss factor." 8 TR 1376.

Mr. Jester's recommendation to deny the adoption of the updated Line Loss Study, or condition its use on the Company's performance of a system loss mitigation plan, is inappropriate. 8 TR 1377; 10 TR 2367. The Company performs a reasonable level of activities related to line loss evaluation and mitigation and continues to explore methods that will help reduce line loss. However, capital investments based on line loss alone would be imprudent as the loss savings are seldom enough to justify capital expenditures solely on this basis. 8 TR 1377.

VII. REVENUE DEFICIENCY CALCULATION AND TIMING ISSUES

For the reasons discussed in this Brief and as set forth in the evidence presented by Consumers Energy, Consumers Energy requests the Commission find that, without rate relief,

Consumers Energy will experience a revenue deficiency for the test year ending May 31, 2016 of $198.6 million (which includes the $33.5 million impact of new depreciation rates). The calculation of this deficiency is summarized in Appendix A.

Significant events which are projected to occur in the Company's May 2016 test year impact the Company's revenue deficiency. 5 TR 314-315. The first event is related to the purchase the Jackson Gas Plant which is expected to close after December 2015. 5 TR 315. There is a $35 million annual revenue requirement associated with the Jackson Gas Plant and, since the final rates in this filing would be implemented prior to the close of the sale, the Company proposes a bill credit to be applied to customers' bills from the time of the final order until the plant becomes fully operational. 5 TR 315; 5 TR 556; Exhibit A-16 (LMC-5).

The second event relates to the retirement of the Company's Classic 7 Plants in April 2016. 5 TR 315. Once these plants are retired, approximately $38 million of primarily ongoing O&M will be removed from customer rates. 5 TR 315. In Exhibit A-19 (LMC-9), the Company has calculated new rates which reflect the removal of the Classic 7 from the Company's revenue requirement. 5 TR 561. The Company is proposing that the rates in this exhibit be implemented when the Classic 7 plants are retired in the April 2016 timeframe. 5 TR 562.

As a result of these events, the Company has created a three step revenue deficiency presentation. 5 TR 314-315. The first step provides the calculation of the Company's revenue deficiency for the projected test year. 5 TR 314. The second step provides in the inclusion of the Jackson Gas Plant revenue requirement. 5 TR 314. The third step removes the Classic 7 Plants from the revenue requirement. 5 TR 314-315. An illustrative example of the above described revenue deficiency steps is provided in Appendix A, lines 7, 9, and 11.

VIII. COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

A. Cost of Service

Company witness Michael H. Ross presented the Company's COSS by rate class. 5 TR 463-479. Mr. Ross described the nature of a COSS:

> "Q. What is a Cost-of-Service Study ('COSS') by rate class?
>
> "A. A COSS by rate class is a systematic functionalization, classification, and allocation of a utility's fixed and variable costs to serve the various rate classes. A COSS achieves two goals. First, the process of preparing the COSS identifies and separates costs associated with the utility's production and distribution of electricity into the jurisdictional electric rate classes. Secondly, the COSS is used to determine the relative contribution to jurisdictional earnings from each of the Company's jurisdictional electric rate classes." 5 TR 463-464.

Mr. Ross' test year analysis can be found at Exhibit A-5 (MHR-1), Schedule F-1 (Historical Year), Exhibit A-11 (MHR-2), Schedule F-1, (Test Year–12 Months Ending May 31, 2016 using 4CP 50/25/25 Production and 12 CP 50/25/25 Transmission), and Exhibit A-11 (MHR-3), Schedule F-1.1 (Test Year–12 Months Ending May 31, 2016 using 4CP 100 Production and 12 CP 100 Transmission). Mr. Ross provides the rationale and the methodology for his COSS analysis in his direct testimony.

In July of 2014, the Michigan Legislature enacted Public Act 169 ("PA 169"), which required the Commission to conduct proceedings to examine cost allocation and rate design methods used to set rates for the State's two largest electric utilities, Consumers Energy and DTE. During much of the current proceeding, Consumers Energy's PA 169 case, Case No. U-17688, was running in parallel with this case, and most of the cost allocation proposals offered by the Company in this case mirrored those being pursued in Case No. U-17688. Most significantly among those was the Company's proposal to adopt a 4CP 100 allocation

methodology for the Company's production-related costs and a 12CP 100 allocation methodology for the Company's transmission-related costs. All of the parties in Case No. U-17688 are also parties to this proceeding (except the Michigan Agri-Business Association), and the recommendations offered regarding cost allocation in this case are duplicative of the recommendations offered in that case, with the most important arguments revolving around the correct choice of production cost allocator. As in this case, Staff proposed a production cost allocator in Case No. U-17688 based on a 4CP 75/25 methodology.

On June 30, 2015, after the close of the record in this case, the Commission issued its Order in Case No. U-17688 resolving all of the cost allocation issues disputed by the parties in that case. Among the most significant conclusions of the Commission was the adoption of Staff's proposed 4CP 75/25 production cost allocation methodology and the Company's proposed 12CP 100 transmission cost allocation methodology. The Commission's Order provides that rates reflecting the new cost allocation methods adopted in that case will be effective beginning December 1, 2015. On those issues where the Commission did not adopt Consumers Energy's proposals in Case No. U-17688, the Company continues to support the arguments made on behalf of those proposals in both cases and continues to believe that the evidence shows that the cost allocations recommended by the Company most accurately align cost allocation with cost causation. However, given the nearly exact identity of issues between the cost allocation recommendations in this case and those in Case No. U-17688, as well as the recentness of that decision and the timing of its implementation, Consumers Energy accepts the outcome of that case as controlling on cost allocation issues decided by that case.

The Company expects to continue pursuing its recommendations that were not adopted at this time in future proceedings. With respect to cost allocation issues addressed in this case,

which were not discussed or adopted in the Commission's Order in Case No. U-17688, the Company continues to support its proposals in this case and requests that they be adopted.

In this case Staff has proposed an allocation for Uncollectible Account expenses different than Staff's proposal in Case No. U-17688. Staff's proposal to allocate Uncollectible Account expenses based on revenue in this case should be rejected. Staff's proposal inappropriately shifts $13 million of uncollectible costs to the Primary class despite the fact that in 2014 gross write-offs for the primary class were only 90,000 and, historically, 90% of gross write-offs are attributable to the Residential class. 5 TR 487-488. Staff's proposal violates the principle of allocating costs based on cost-causation. In contrast, the Company's proposal is consistent with the allocation methodology for Uncollectible Account expenses approved in Case No. U-17688. Staff's recommendation should be rejected.

B. Rate Design and Tariff Issues

Company witness Collins provided the Company's position concerning rate design and certain changes to the Company's tariffs. As Ms. Collins testified, the goal of the rate design provided by the Company in this case was to "1) establish rates that adhere to the cost of service as required by 2008 Public Act 286 ('PA 286'); 2) establish rates that promote efficient use of the Company's electric system and promote customer energy efficiency; 3) establish rates that promote a favorable business climate while meeting the other stated objectives; and 4) provide the Company with a fair opportunity to collect its revenue requirements." 5 TR 536.

Ms. Collins presented the Company's proposed rate design changes for its Residential, Secondary, and Primary Rate Classes. 5 TR 542-556. Ms. Collins provided an overview of the Company's rate design proposals as follows:

"Q. What changes is Consumers Energy proposing to make to the Company's electric rates?

"A. The Company is proposing the following changes:

"Elimination of Subsidies – The Company is proposing to eliminate the General Service Large Industrial Economic Development Primary Rate E-1. The Company currently has one customer on Rate E-1, whose contract term runs through November 30, 2015. The proposed rates reflect the elimination of that subsidy effective December 1, 2015.

"Q. What other rate changes are you proposing in this case?

"A. Residential Rate Modifications – The Company is proposing to maintain its existing residential rates, Residential Service Secondary Rate ('RS') and Residential Service Time of Day Rate ('RT'), as well as its Experimental Residential Plug-In Electric Vehicle rates, ('REV-1' and 'REV-2').

"Secondary Rate Class Modifications – The Company is proposing to maintain its existing secondary rates, General Service Rate ('Rate GS') and General Service Demand Rate ('Rate GSD'). However, the Company is proposing to modify these rate designs to remove the seasonal differential in the energy charges, thus volumetric energy rates would not fluctuate by season as they do today.

"Primary Rate Class Modifications – The Company is proposing to maintain its existing primary rates, General Primary Rate ('Rate GP'), General Primary Demand Rate ('Rate GPD'), General Primary Metal Melting Pilot Rate ('MMPP'), and General Primary Time of Use Rate ('Rate GPTU'). However, the Company is proposing rate design changes within each of these rate schedules. These rate design changes will be discussed later in my testimony." 5 TR 537.[24]

The Company is also incorporating the Rate General Primary Demand ("GPD") rate design proposals from Case No. U-17688 in this case. 5 TR 547.

[24] As explained below, the Company ultimately adopted Staff's recommendation to maintain seasonal differentials in the Company's Secondary and certain Primary Rates. 5 TR 572-573.

With respect to tariff changes, Ms. Collins has listed proposed tariff changes on Exhibit A-84 (LMC-17). That exhibit contains a listing of the proposed tariff changes together with a brief summary of the changes. Included in that exhibit is Tariff Sheet C-32.20 which provides an update to the non-transmitting meter charges. 5 TR 581.

Various intervenors took issue with certain of Ms. Collins' positions relating to rate design and tariff changes.

1. Residential Customer Charge

Staff witness Gottschalk claims that Staff's COSS supports a Residential Customer Charge below what the Company has proposed and recommends that the Residential System Access charge remain at $7.00/month instead of being increased to $7.50, as proposed by the Company. 9 TR 1781. Company witness Collins explained that the Company's COSS supports an increase of the monthly customer charge to $7.50; however, to the extent that a different cost of service is adopted in the final rates decided by the Commission, the Company agrees that the customer charge should be adjusted accordingly so long as the charge is not reduced below the current $7.00/month level.

2. Seasonal Differentials

In its initial filing, the Company proposed to remove the seasonal differentials from its Secondary and certain Primary rates. 5 TR 545-550. Staff opposed the Company's proposal and recommended that seasonal differentials be maintained in energy rates for non-demand rates in order to maintain the price signals sent which recognize the temporal cost of energy production. 9 TR 1854-1855. In light of Staff's opposition to the Company's proposal, the Company agrees, for the purposes of this case, that the seasonal differentials should be maintained and supports Staff's approach to determining seasonal differentials as recommended by Staff witness Revere. 5 TR 572-573.

3. Senior Income Assistance Discounts

The Commission should reject Energy Michigan witness Alexander J. Zakem's recommendation to separate senior and income assistance discounts into delivery and power supply components and collect those discounts through separate delivery and power supply surcharges. 9 TR 1670. This recommendation improperly shifts more cost responsibility to Full Service customers for the benefit of ROA customers.

Ms. Collins explained that, consistent with Commission approved practice, the responsibility for these discounts should be spread to all customers and collected through the Company's delivery charges. 5 TR 573. Furthermore, the Senior and Income Assistance credits are applied as offsets to, and are based on, the monthly System Access Charge amount as determined by the cost of service. 5 TR 573. There is no reasonable rationale for forcing Full Service customers to bear any more responsibility for these subsidies than ROA customers, particularly since Consumers Energy must assume the provider of last resort responsibilities and Alternate Energy Suppliers do not provide any service to these vulnerable classes of customers. 5 TR 573.

4. Joint Ownership Substation Credit

HSC witness Gorman's recommended change to the calculation of the Joint Ownership Substation Credit should be rejected as it is not feasible and, if approved, would produce unreasonable results. Mr. Gorman recommends a change in the calculation of the joint substation ownership credit such that the credit is applied to the customer's metered maximum demand on each substation, each billing month, instead of on the Company proposed method which would utilize the previous calendar year's ratio of the customer's owned substation maximum demand to the Company's owned substation maximum demand. 10 TR 2241. However, the Company currently does not have the functionality in place to perform the monthly

calculation as recommended by Mr. Gorman. Company witness Collins explained that significant programing changes would be required to determine and store the monthly metered maximum demand on each substation which would be required by Mr. Gorman's proposal. 5 TR 575-576. These programing changes would take time and resources to implement. 5 TR 575-576.

The Company's original proposal, which uses the previous calendar year's ratio of the customer's owned substation maximum demand to the Company's owned substation maximum demand, provides a more reasonable methodology. 5 TR 576. The use of a static ratio is further supported by the fact that the Company's and the customer's investment in a substation would not change monthly, and thus a monthly calculation would not necessarily reflect each party's total substation share in serving the load. 5 TR 576.

5. GPD Rate Design

The Commission should reject ABATE witness James T. Selecky's GPD rate design proposal which would collect 100% of production demand costs in the power supply demand charges. 10 TR 2204. The Company's proposal to collect approximately 70% of capacity costs in the On-Peak Demand charges and the remaining through the energy charges provides the most reasonable and equitable results for GPD customers. 5 TR 576.

First, Ms. Collins explained that it is reasonable for the Company to charge some capacity in all hours as opposed to Mr. Selecky's recommendation which would have the effect of only charging capacity during on-peak hours. 5 TR 576-577. Second, Mr. Selecky's proposed increase in the On-Peak Demand charge presents a considerable change in the On-Peak Demand rates for GPD which results in a benefit to voltage level 3 customers but harms customers served at voltage levels 1 and 2. 5 TR 578. Ms. Collins provided Exhibit A-82

(LMC-15) which illustrates the GPD interclass inequity created by Mr. Selecky's proposal and presented a detailed explanation of that exhibit as follows:

> "Exhibit A-82 (LMC-15) shows average rates and impacts to customers at various load factors at each voltage level. This assumes each customer has a monthly demand of 1 MW. Column (d) shows the average rate under today's approved rates. Column (e) shows the average rates under the Company's proposal in this case, which collects approximately 70% of the capacity costs through the On-Peak Demand charges. Column (f) shows the average rates using the proposal of Mr. Selecky which collects 100% of the capacity costs through the On-Peak Demand charges. When you compare the average rates in column (e) to column (f), only customers in voltage level 3 see a decrease in average rate. This is because the Company's initial proposal collects 70% of capacity costs in total through the On-Peak Demand charges (total of voltage levels 1, 2, and 3). The On-Peak Demand charge is set for voltage level 1 and then a differential is applied to set increased On-Peak Demand charges for voltage level 2 and voltage level 3. If 100% of the production capacity is collected through the On-Peak Demand charge, the On-Peak Demand charge for voltage level 1 would be set to collect 100% of the capacity allocated to voltage level 1 by the cost of service. For voltage level 2, the On-Peak Demand charges would be set to collect 100% of the capacity allocated in the cost of service to voltage level 2. The same would be done in voltage level 3. By setting these demand charges by voltage level to collect all of the allocated capacity, voltage level 3 would see lower On-Peak Demand charges than voltage level 1 and 2. Therefore, voltage level 3 customers would see a benefit from this design, but voltage level 1 and 2 would pay more than they would with the Company's proposed design." 5 TR 577-578.

Moreover, in its June 30, 2015 final Order in Case No. U-17688, the Commission recently approved GPD rate design which supports the Company's proposal in this case. Case No. U-17688, June 30, 2015, Order, pp. 24-26. In Case No. U-17688, the Commission approved GPD rate design which collects 75% of capacity costs through demand charges and 25% through an energy charge as opposed to the recovery of 100% of capacity costs on the basis of demand. *Id*. In this case, the Company has proposed to collect a slightly lower amount of GPD capacity

costs through demand charges as it provides a more equitable reflection of the COSS performed for this proceeding. Exhibit A-82 (LMC-15).

In addition to recommending a similar proposal to ABATE's GPD proposal above, Wal-Mart witness Chriss recommended that GPD should be excluded from the Company's Revenue Adjustment Mechanism. This recommendation should be rejected. Mr. Chriss states that demand metered rates such as GPD would be decoupled from kWh sales through the rate design and that would be sufficient to assure the Company's revenue requirement. However, since the Company does not agree with Mr. Chriss' proposal to collect 100% of the capacity in the demand charges, which is inconsistent with Commission directives in Case No. U-17688, the decoupling through rate design that he proposes cannot be achieved. 5 TR 578.

6. <u>DPP and Time-of-Use Rates</u>

MEC/CARE/NRDC witness Jester presented DPP and time-of-use rate proposals which mirror the recommendations proposed by MEC/CARE/NRDC in Case No. U-17688. 10 TR 2367-2387. These recommendations lack merit and should be rejected by the Commission.

Mr. Jester's proposals lack appropriate analysis and could be devastating to Michigan's industrial and agricultural competitiveness. 5 TR 579. The deficiencies in Mr. Jester's proposals were extensively addressed by Company witness Collins as follows:

> "Q. Mr. Jester makes several proposals regarding moving all customers to dynamic pricing rates and eliminating existing time-of-use rates such as Residential Electric Vehicle ('REV'), General Primary Time of Use ('GPTU'), and MMPP. Do you agree with his recommendations?
>
> "A. No. Mr. Jester provides no evidence to suggest that his dynamic pricing proposals will result in competitive and affordable rates. There is very little detail to how Mr. Jester's proposal would actually work. He provided no tariff language or other documentation that describes how the rates would be administered, established, implemented, or verified. Further, Mr. Jester failed to provide any typical

> bill impacts for customers and fails to provide rate impacts that would allow the Company and its customers to understand what dynamic pricing would mean in energy costs for each customer class. In addition, he provides no evidence that his rate design would even provide the Company with a reasonable opportunity to collect its revenue requirement. Without such information, his proposals cannot be given serious consideration. Mr. Jester's proposals are speculative at best, and at worst could be devastating to the State of Michigan's industrial and agricultural competitiveness." 5 TR 579.

As a result of the numerous shortcomings and harmful consequences discussed above, the Commission should reject Mr. Jester's DPP and time-of-use rate proposals.

7. General Primary Time of Use ("GPTU") Rate Design

The Commission should approve the Company's proposed changes which increase the high-peak and mid-peak time blocks used in the GPTU rate. Kroger witness Neal Townsend opposes this change and suggests that, if the Company's proposal is approved, the high-peak block should be expanded but the mid-peak block should remain at one hour before the high-peak and one hour after the high-peak. 9 TR 1749-1750. Mr. Townsend's opposition and counterproposal lack merit.

In revising the time blocks for the GPTU rate, the Company relied on MISO hourly Location Marginal Price ("LMP") data to determine the breaks in the highest-priced periods. 5 TR 580. The LMP prices indicated a clear three-hour high-period and also indicated a clear four-hour mid-peak period. 5 TR 580. The Company's approach was also supported by Staff witness Mark J. Pung as follows:

> "Q. Does Staff support the Company's Rate GPTU time block change proposal?
>
> "A. Yes. Staff agrees with the Company that it is important to properly motivate and incentivize customers to avoid the most critical summer and winter capacity periods using the appropriate price signals. The Company's proposal is based

> upon a thorough review of forecasted LMP hourly prices, which Staff agrees indicates a three-hour high-peak period. Overall, this rate will continue to offer customers the opportunity to reduce energy costs by reducing energy usage during the higher priced time periods." 9 TR 1834.

The Company's proposal is reasonable and should be approved by the Commission.

8. Educational Institutions

PA 286 requires that public and private schools, universities, and community colleges are charged retail rates that reflect the actual cost of providing service to those customers. MCL 460.11(9). In order to meet this requirement the Company split educational institutions into their own cost class in order to determine their specific costs-to-serve. 5 TR 553. The Company then established credits (or charges) that are applied to the bills for educational institution customers (as they were billed at the standard rate) to get their billing at the cost-to-serve level. 5 TR 553. However, this approach resulted in inconsistent power supply and delivery charges to Education Institution customers which, in some cases, resulted in these customers paying more or less than the other general service customers served at the same voltage. 5 TR 553.

In order to alleviate the variances discussed above, the Company is proposing that, for rate design, Educational Institution customers be included in the cost study column with all other general service customers served at similar voltage levels. 5 TR 553-554. The Company further proposes to provide all Educational Institution customers with a credit that removes the subsidies for Income Assistance and Senior Citizens, which these customers are not required to pay. 5 TR 554. These proposals, which are contingent on the approval of the Company's cost allocation proposals in this case, ensure that Educational Institution customers will not pay a cost-based rate higher than similarly situated customers and will receive a credit to remove any obligation to pay rate subsidies. 5 TR 553-554.

The Commission should also take note of the fact that, consistent with the credits determined in Case No. U-17688, Educational Institution rates should be evaluated based on the specific determinants and costs proposed or approved in a given case. Case No. U-17688, 2 TR 48; Case No. U-17688, June 30, 2015, Order, p. 27. For instance, Staff's 75/0/25 production cost allocation methodology, if also approved in this case, would effectively negate the Company's above discussed Income Assistance and Senior Citizen subsidy credit which was based on the Company's initially filed determinants and costs. Thus, if the Commission adopts Staff's 75/0/25 production cost allocation methodology in this case, the Company proposes to continue the subsidy credit, as described above, and provide all Secondary and Primary Educational Institution customers a power supply credit that is consistent with the power supply credit approved for Primary Educational Institution customers in Case No. U-17688. Case No. U-17688, 2 TR 48. This approach would ensure cost-based rates for Educational Institution customers as required by 2008 PA 286.

9. <u>Demand Response Rates</u>

Consumers Energy requests a change to the summer power supply charges included in the Company's DPP tariff rates. Company witness Warriner explained that as the Company nears completion of the AMI system development that will enable customer enrollment in DPP programs, it is necessary to set critical peak period prices at a level that incents customers to take actions that will realize the average customer demand reductions planned for in the AMI business case. 6 TR 951-952. The residential price elasticity identified in the DPP pilot was utilized to determine the recommended rates for residential service rate RS. 6 TR 952. The proposed critical peak prices for rates GS, GSD, and GP are based on the ratio of each rate category's summer price levels to the comparable rate RS summer charges. 6 TR 952. The

Company reviewed existing critical peak pricing programs at other utilities and believes its proposed rates are consistent with similar rates in other utility service areas. 6 TR 952.

Staff witness Revere proposed DPP rates slightly lower than those proposed by the Company, contending that "[s]etting the price at under a dollar may help customer acceptance, while still producing the desired results." _9 TR 1859. Staff's recommended rates are generally consistent with the Company's proposal to increase the current DPP rates. If the Commission accepts Staff's proposed rates, the claim that a lower price (less than one dollar per kWh) will help with customer acceptance will need to be validated as the Company gains experience with customer participation in dynamic peak pricing.

The Company's proposed critical peak price rates are as follows:

Critical Peak Pricing			
Power Supply Charges			
Summer Energy Charge			
for the hours of 2:00PM to 6:00PM during a critical peak event day			
	Current	Proposed	Staff Proposed
RATE CATEGORY	$/kWh	$/kWh	$/kWh
RESIDENTIAL SERVICE SECONDARY RATE RS			
Residential With Dynamic Pricing (RDP) - 1007	$0.500000	$1.000000	$0.950000
Residential With Dynamic Pricing Rebate (RDPR) - 1008	-$0.500000	-$1.000000	-$0.950000
GENERAL SERVICE SECONDARY RATE GS			
Commercial With Dynamic Pricing - 1121	$0.500000	$1.000000	$0.950000
Industrial With Dynamic Pricing - 1121	$0.500000	$1.000000	$0.950000
GENERAL SERVICE SECONDARY DEMAND RATE GSD			
Commercial With Dynamic Pricing - 1156	$0.500000	$0.721681	$0.950000
Industrial With Dynamic Pricing - 1156	$0.500000	$0.721681	$0.950000
GENERAL SERVICE SECONDARY RATE GP			
Commercial (Customer Voltage Level 1, 2 or 3) With Dynamic Pricing - 1211			
Industrial (Customer Voltage Level 1, 2 or 3) With Dynamic Pricing - 1212			
Customer Voltage Level 1	$0.500000	$0.719680	$0.794722
Customer Voltage Level 2	$0.500000	$0.761201	$0.799669
Customer Voltage Level 3	$0.500000	$0.809362	$0.800000

6 TR 952; Exhibit S-6, Schedules f-3a and f-3b, pages 5, 6, 8, 10, 14, 15, and 16.

10. <u>AMI Opt-Out Tariff</u>

In Case No. U-17000, the Commission directed that utilities which implement AMI should make available an opt-out option, based on cost-of-service principles, for customers who

do not wish to have a smart meter. Case No. U-17000, Order dated September 11, 2012, page 5. Company witness Warriner explained that the Company's AMI Program reasonably provides customers the flexibility to abstain from receiving a smart meter, for whatever reason they deem appropriate. 6 TR 960. A cost-of-service based Opt-Out tariff is designed to recover the incremental costs which are caused by customers' decision to opt out of the standard AMI smart meter technology. 6 TR 960. An opt-out option (also referred to as the option to use a non-transmitting meter) is desired by a very small fraction of the Company's customers. 6 TR 961-962. This option does not result in any benefits to the general customer population, and it is therefore appropriate for customers choosing to opt-out of the AMI Program to pay the costs of developing systems and business process necessary to support that option. 6 TR 962.

Consumers Energy's existing opt-out tariff was approved in Case No. U-17087. See Case No. U-17087, Order dated June 28, 2013, page 9[25]. However, the costs of implementing the Opt-Out option have proven to be substantially greater than the pre-implementation estimate which was developed and presented in Case No. U-17087. 6 TR 962. This increase in costs is also influenced by the low rate of customers who have chosen the opt-out option. 6 TR 962. Mr. Warriner explained:

> "The costs of implementing the smart meter deployment exceptions process have proven to be substantially greater than the pre-implementation estimate which was developed and presented in Case No. U-17087. The Company's projection of customer participation in the non-transmitting meter opt-out option has also been revised downward based on the Company's experience to date. A lower participation estimate causes the per customer cost of the smart meter deployment exceptions process to increase,

[25] The Commission's June 28, 2013 Order was appealed by the Attorney General and several residential customers who were not parties to the underlying Case No. U-17087. In an unpublished Opinion dated April 30, 2015, the Court of Appeals affirmed the Commission's authority to approve rates to recover the costs of an AMI opt-out program, but remanded the case to the Commission for consideration of the purpose and nature of the opt-out tariff and a determination of the costs recovered by that tariff. *Attorney General v Public Serv Comm'n*, Docket Nos. 317434 and 317456, unpublished Opinion dated April 30, 2015, pages 5-6. A copy of the Court of Appeals' Opinion is attached hereto as Appendix F.

> because the costs incurred need to be recovered from a smaller group of customers. Decreases in customer participation in the opt-out option also increases the costs to manually read meters as having fewer non-transmitting metered customers to serve results in an even more inefficient manual meter reading process than projected in Case No. U-17087. As a result, updated opt-out charges results in higher costs of service for non-transmitting (opt-out) meter customers." 6 TR 962.

Mr. Warriner explained in detail the work and costs associated with providing an AMI opt-out option. 6 TR 962-964; Exhibits A-121.

Exhibit A-121 provides a comparison of the Company's existing (Case No. U-17087) Opt-Out tariff with an Opt-Out tariff based on current costs. Exhibits A-122 and A-123 provide the historical detail on the development of the Case No. U-17087 Opt-Out tariff rates. Exhibit A-124 updates the Case No. U-17087 Opt-Out tariff rates with current cost and participation estimates. 6 TR 955-956. An AMI Opt-Out tariff continues to be necessary in order to provide customers an option to not have an AMI meter associated with their electric service provided by the Company, and recover costs associated with providing that option from customers exercising that option. As explained by Mr. Warriner, the costs of providing an opt-out option have increased since Case No. U-17087, and it would be appropriate for the Commission to increase the fees associated with the Opt-Out tariff as shown in Exhibit A-121. 6 TR 964.[26]

In addition, Consumers Energy also proposes to remove the exclusion of apartment complexes and other dwellings with meter banks serving multiple customers from the Non-Transmitting Meter tariff. Mr. Warriner explained that this exclusion is not necessary given

[26] Mr. Warriner also explained that actual opt-out revenues billed for April 2014 through March 2015 amounted to $278,427. It would be reasonable to include this revenue amount as an adjustment to the Company's projection of test year jurisdictional revenue. 6 TR 965. If the Commission decides to change the existing Opt-Out tariff fees from those approved in Case No. U-17087, a modification to the historical amount billed would be appropriate to reflect the new Opt-Out tariff rates. 6 TR 965.

the high customer acceptance rate of smart meters. This proposed change is reflected in Company witness Collins' tariff sheet C-32.20, rule C5.5. 6 TR 951.

11. Threats of Violence Tariff

Since 2010, Consumers Energy has experienced over 500 incidents of threats of violence annually. 6 TR 808. In 2014, 13 Consumers Energy employees have been assaulted, and of the threats reported during the same time period, 16% involved a weapon and 43% involved a dog resulting in an employee being bitten. 6 TR 809. In response to such threats and acts of violence against its employees and contractors, the Company is proposing to implement a tariff addressing threats or acts of violence.

Under the proposed threats or acts of violence tariff, the Company will disconnect service of a customer who has a confirmed act or threat of violence against a Company employee or contractor. 6 TR 808. Depending on the circumstances, different threat codes are assigned to the customer's account to ensure awareness of Company representatives in the service territory. 6 TR 809. On threat coded accounts, the Company will perform a semiannual review, or review the account at the request of the customer, and service will remain shut off until it is clear that the threat has been resolved. 6 TR 815. Additionally, the Company would have the ability to collect reasonable costs associated with the threat or act of violence from the customer prior to restoring service. 6 TR 810.

The Staff opposes this proposal. Staff witness Gottschalk indicated that "disconnecting service to a customer who has already made a threat of violence would escalate the situation . . . ." 9 TR 1779. Staff's concern ignores the fact that when the threat or act of violence occurs, the customer account is already eligible for disconnection, and the Company representative is often already onsite disconnecting service. 6 TR 814. Company witness Michael J. Williams testified, "These disconnections could be occurring for a variety of reasons, such as nonpayment or theft

on the account. If the Company representative was prevented from discontinuing service by the act of violence, the Company can still disconnect service regardless of this tariff modification." 6 TR 814. Additionally, Staff expressed concern regarding the tariff's cost recovery provision. 9 TR 1780. However, the Company's proposed tariff only seeks recovery of the incremental reasonable costs that are directly associated with the actions of the customer involved. 6 TR 815. These are the costs associated with the Company's investigation, the operating crews required to terminate service, and any other directly related expenses incurred by the Company due to an injury as a result of a physical assault or related threat. 6 TR 810. Absent directly recovering these costs from the individual who made the threat or performed the act of violence, the costs incurred by that individual's action are passed on to all ratepayers. 6 TR 815.

Contrary to the contentions of Residential Customer Group ("RCG"), the Company's tariff proposal is not related to AMI or the installation of Smart Meters. 10 TR 2146. The tariff will not require a customer to accept a smart meter. 6 TR 813. The purpose of the proposal is to ensure the safety and protection of utility employees and contractors. 6 TR 813. As such, the Company requests that the Commission approve the Company's threat or acts of violence tariff.

12. <u>Flat Fee for Residential Underground Service</u>

Company witness Palkovich supports the Company's proposal to amend its tariffs to charge residential new business customers a flat fee for a new service that is underground instead of the current practice of a per foot charge. 8 TR 1342. The tariff change would result in a flat fee of $350 for new permanent residential secondary services, for trench distances up to 150 linear feet, and an additional $4.50/ft charge will be applied for all feet thereafter. 8 TR 1342. This pricing is consistent with what the Company is currently charging customers on a per foot basis. 8 TR 1342-1343.

13. Other Tariff Issues

Energy Michigan witness Zakem's criticisms of the Company's proposed modification to the Tariff Sheet No. E-7.00 should be rejected. 9 TR 1682-1684. This tariff sheet deals with metering for ROA customers and the requirement that ROA customers install a phone line to their meter for the Company to call monthly and download usage information. 5 TR 574.

The intent of the additional tariff language is to clarify that it is the customer's responsibility to inform the Company if there is a problem with their phone line that is being addressed, particularly when the customer needs additional time to resolve the issue. 5 TR 574. This language is important because, if the Company is unable to call the meter using the phone line, the customer will receive a manual read notice and after three consecutive manual read notices, the tariff provides for returning the customer to full service. 5 TR 574. Mr. Zakem's proposed rejection of this language unreasonably forces the Company to anticipate customer telephonic communication issues. If the Company is aware that a customer is working on the repairs necessary to enable the automatic reads, the Company can then postpone returning the customer to full service. 5 TR 574.

With the above noted, the Company proposes a further modification to the tariff, to add the words "of the status," to clarify the Company's intent. Exhibit A-81 (LMC-14) provides the additional modification as follows:

> "It is the customer's responsibility to notify the Company **of the status** of any telephonic communication issues that may inhibit the Company's ability to access meter data electronically." Exhibit A-81 (LMC-14) (Emphasis added.)

MEC/CARE/NRDC witness Jester asserts that the Company did not include a revised tariff sheet for Rule C8 relating to its line loss factor. 10 TR 2360. While it is correct that this tariff sheet was inadvertently not updated with the Company's initial filing, the tariff sheet was

revised in a Staff audit response that was provided to all requesting parties through discovery. 5 TR 579. The Company subsequently provided a revised version of Rule C8 as Exhibit A-83 (LMC-16).

IX. APPEAL OF ALJ DECISION REGARDING PROTECTIVE ORDER

On May 5, 2015, a hearing took place in this proceeding to consider Consumers Energy's Motion for a Protective Order regarding certain confidential materials provided to MEC/NRDC by the Company during the discovery phase of this case. While the parties agreed generally with the issuance of a Protective Order pertaining to those materials, MEC/NRDC proposed language in the Protective Order that would authorize them to retain the Company's confidential materials after the close of the proceedings in this case. At the May 5 hearing, the ALJ granted MEC/NRDC's request to retain the Company's confidential information, albeit with time restrictions linked to the filing of Consumers Energy's next electric general rate case and any PSCR cases that commence before that time. 3 TR 65-67. Pursuant to R 792.10433, Rule 433(5), Consumers Energy appeals that decision for the reasons stated in oral arguments on May 5, 2015, 3 TR 56-60, and in the Company's May 18, 2015 Objection to Proposed Order Filed by MEC and NRDC, document 0236 on the Commissions E-Docket page for Case No. U-17735.

X. CONCLUSION

For the reasons discussed in this Brief and as set forth in the evidence presented by Consumers Energy, Consumers Energy requests that the Commission authorize an increase in electric rates sufficient to produce additional annual revenues in the final net amount (i.e. the accumulated total of the three stages of rate adjustment proposed by the Company in this case) of approximately $198.6 million, and grant the other related relief as set forth in more detail in this Brief and the record evidence.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Dated: July 17, 2015

By: Bret Totoraitis Digitally signed by Bret A. Totoraitis Date: 2015.07.17 16:51:06 -04'00'

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APPENDICES A-F

Consumers Energy Company
MPSC Electric Rate Case No. U-17735
Comparison of the May 2016 Test Year Revenue Deficiency
for CECo Positions and the MPSC Staff Position (000)

Line No.	Description	Jurisdictional Basis CECo Initial Position	MPSC Staff as-Filed Position	CECo Initial Brief Presentation	Variance ((c) less (d))
	(a)	(b)	(c)	(d)	(e)
1	Rate Base	$ 9,167,211 [1]	$ 9,045,731 [1]	$ 9,247,692 [1]	$ (201,961)
2	Rate of Return	6.50% [2]	6.04% [5]	6.38% [6]	-0.34%
3	Income Required	$ 595,660	$ 546,405	$ 589,725	$ (43,320)
4	Adjusted Net Operating Income	494,355 [3]	528,095 [3]	466,390 [3]	$ 61,705
5	Income Deficiency	$ 101,305	$ 18,310	$ 123,336	$ (105,025)
6	Revenue Multiplier	1.6367 [4]	1.6367 [4]	1.6367 [4]	-
7	Revenue Deficiency (Sufficiency)	$ 165,801	$ 29,968	$ 201,863	$ (171,896)
8	Revenue Deficiency (Sufficiency) - Jackson Plant	$ 35,404	$ 34,291	$ 35,164 [6]	$ (873)
9	Total Revenue Deficiency (Sufficiency)	$ 201,205	$ 64,259	$ 237,027	$ (172,769)
10	Revenue Deficiency (Sufficiency) - Classic 7 Plants	$ 38,461	$ 38,461	$ 38,461	$ -
11	Total Revenue Deficiency (Sufficiency)	$ 162,744	$ 25,798	$ 198,566	$ (172,769)

Footnotes:

[1] CECo Initial Brief, Appendix B

[2] Ex. A-9 (ADJ-1), Schedule D1

[3] CECo Initial Brief, Appendix C

[4] Ex. A-8 (NNB-50), Schedule C2

[5] Ex. S-4 (KDM), Schedule D1

[6] CECo Initial Brief, Appendix E, page 1 of 2

Consumers Energy Company
MPSC Electric Rate Case No. U-17735
Comparison of the May 2016 Test Year Rate Base for
CECo Positions and the MPSC Staff Position (000)

Line No.	Description	Jurisdictional Basis: CECo Initial Position [1]	MPSC Staff as-Filed Position [2]	CECo Initial Brief Presentation	Variance ((c) less (d))
	(a)	(b)	(c)	(d)	(e)
1	Utility Plant in Service				
2	Plant in Service	$ 12,176,468	$ 12,144,649	$ 12,176,553 [3]	$ (31,904)
3	Plant Held for Future Use	5,158	5,158	5,158	(0)
4	Construction Work in Progress	967,902	935,389	967,902	(32,513)
5	Total Utility Plant	$ 13,149,529	$ 13,085,196	$ 13,149,614	$ (64,418)
6	Less: Accum. Depreciation and Amortization	$ (4,614,935)	$ (4,614,121)	$ (4,632,583) [4]	$ 18,462
7	Net Utility Plant	$ 8,534,594	$ 8,471,075	$ 8,517,031	(45,956)
8	Retainers & Customer Advances	$ (28,726)	$ (28,726)	$ (28,726)	-
9	Working Capital	$ 661,342	$ 603,383	$ 759,386 [4]	(156,003)
10	Total Rate Base	$ 9,167,211	$ 9,045,731	$ 9,247,692	$ (201,959)

Footnotes:

[1] Ex. A-7 (NNB-44), Schedule B1, Development of Rate Base

[2] Ex. S-2 (JSG) Schedule B1, Rate Base

[3] Ex A-78 (NNB-68) Schedule B1, Development of Rate Base

[4]

$	661,342	CECo Initial Position
	78,112	Bonus Depreciation Balance Sheet Impact
		See Exhibit A-93 (AJD-16)
		65.11% electric for cash adjustment
		64.96% electric for accrued tax adjustment
	19,932	Removal of REP liability accounts, Ex A-80 (NNB-70)
$	759,386	

Consumers Energy Company
MPSC Electric Rate Case No. U-17735
Comparison of the May 2016 Test Year Net Operating Income
(NOI) for CECo and the MPSC Staff Positions (000)

Line No.	Description	Jurisdictional Basis: CECo Initial Position [1]	MPSC Staff as-Filed Position [2]	CECo Initial Brief Presentation	Variance ((c) less (d))
	(a)	(b)	(c)	(d)	(e)
	Revenues				
1	Total Revenues	$ 4,203,659	$ 4,204,819	$ 4,203,659	$ 1,160
	Expenses				
2	Fuel Used and P&I Expense	$ 2,245,948	$ 2,245,873	$ 2,245,948	$ (75)
3	Other O&M	644,953	586,179	651,166 [3]	(64,987)
4	Depreciation and Amortization Expense	475,855	474,845	511,130 [4]	(36,285)
5	Property and Other Taxes	181,841	182,544	182,344	200
6	Local and State Income Taxes	37,208	40,694	34,619 [4]	6,075
7	Federal Income Tax	127,827	150,923	116,389 [4]	34,534
8	Total Expenses	$ 3,713,631	$ 3,681,058	$ 3,741,596	$ (60,538)
9	Net Operating Income	$ 490,028	$ 523,761	$ 462,063	$ 61,698
10	Add: AFUDC	4,327	4,326	4,327	(1)
11	**Adjusted Net Operating Income**	$ 494,355	$ 528,095	$ 466,390	$ 61,705

Footnotes:

[1] Exhibit A-8 (NNB-49), Schedule C1

[2] Ex. S-3 (RFN), Schedule C-1, page 1 of 1

[3] CECo Initial Brief, Appendix D

[4] Exhibit A-79 (NNB-69), Schedule C1 and CECo Initial Brief, Appendix D

$	475,855.00	Jurisdictional Dep Exp with Jackson Plant Removed, Exhibit A-8 (NNB-49)
	35,275	*Additional Deprection Expense resulting from U-17653
	511,130	Juridictional Dep Exp with Jackson Plant Removed, A-79 (NNB-69)

*Note: The total revenue requirement impact of addition depreciation expense from U-17653

	35,275	Depreciation Expense
	(1,814)	Accumulated Depreciation
$	33,461	Total Revenue Requirement Impact U-17653

Calculation of MPSC Staff Jurisdictional NOI (000)

Line No.	Description	MPSC Staff Position[1]	Jursidictional Factors	Jurisdictional MPSC Staff Position[1]
	(a)	(b)	(c)	(d)
	Revenues			
1	Total Revenues	$ 4,229,447	0.994177	$ 4,204,819
	Expenses			
2	Fuel, P&I, & Transmission Expense	$ 2,268,446	0.990049	$ 2,245,873
3	Other O&M Expense	588,163	0.996627	586,179
4	Depreciation & Amortization Expense	476,531	0.996462	474,845
5	Property and Other Taxes	182,879	0.998168	182,544
6	Local and State Income Taxes	40,775	0.998015	40,694
7	Federal Income Tax	150,445	1.003180	150,923
8	Total Expenses	$ 3,707,239		$ 3,681,058
9	Net Operating Income	$ 522,208		$ 523,761
10	Add: AFUDC	4,354	0.993569	4,326
11	**Adjusted Net Operating Income**	$ 526,562		$ 528,095

Footnotes:

[1] Ex. S-3 (RFN-1), Schedule C-1, page 1 of 1

Consumers Energy Company
MPSC Electric Rate Case No. U-17735
Comparison of the May 2016 Test Year Other O&M
for CECo and the MPSC Staff Positions (000)

Line No.	Description	CECo Initial Position [1]	MPSC Staff as-Filed Position [2]	CECo Initial Brief Presentation	Variance ((c) less (d))
	(a)	(b)	(c)	(d)	(e)
	Other O&M Comparison - Total Company				
1	Electric Distribution	$ 239,439	$ 213,370	$ 239,439	$ (26,069)
2	Fossil & Hydro Generation	176,827	161,086	176,827	(15,741)
3	Business Technology Solutions	41,411	39,649	41,411	(1,762)
4	Smart Grid Program	14,238	9,275	14,238	(4,963)
5	Pension Plan	37,447	40,900	40,900	-
6	SERP	4,588	-	4,588	(4,588)
7	DC SERP	159	-	159	(159)
8	Defined Company Contribution Plan	5,738	5,738	5,738	-
9	401(k) Savings Plan	7,012	7,041	7,041	-
10	Active Health Care/Insurance/LTD	27,534	27,607	27,607	-
11	Retiree Health Care & Life Insurance	(9,223)	(6,546)	(6,546)	-
12	Corporate	54,285	56,428	54,285	2,143
13	Uncollectibles	30,799	23,859	30,799	(6,940)
14	Injuries & Damages	4,653	5,337	4,653	684
15	Accounts Receivable Sales Costs	714	726	714	12
16	Jobwork Expense	7,535	7,494	7,535	(41)
17	Incentive Compensation	12,807	-	12,807	(12,807)
18	Test Year Other O&M	$ 655,963	$ 591,964	$ 662,195	$ (70,231)
	Remove:				
19	Jackson Gas Plant O&M - Annual	8,646	$ 3,603	$ 8,646	$ (5,043)
20	Jackson Gas Plant Insurance Premium - Test Year	445	$ 198	$ 445	$ (247)
21	Test Year Other O&M	$ 646,872	$ 588,163	$ 653,104	
22	Jurisdictional Factor	0.997033	0.996627	0.997033	
23	Test Year Jurisdictional Other O&M	$ 644,953	$ 586,179	$ 651,166	$ (64,987)

Footnotes:

[1] Ex. A-8 (NNB-53), Schedule C5

[2] Ex. S-3 (RFN) Schedule C5

Consumers Energy Company
MPSC Electric Rate Case No. U-17735
Weighted Average Cost of Capital - 10.70% Return on Equity

		Capital Structure				Weighted Cost			
Line	Description	Amount Outstanding	% of Permanent Capital	% of Total Capital	Cost Rate	Permanent Capital	Total Cost %	Conversion Factor	Pre-tax Weighted Cost
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Long-Term Debt	$ 4,965,255,000	47.17%	37.30%	5.02%	2.37%	1.87%	1.0000	1.87%
2	Preferred Stock	37,315,000	0.35%	0.28%	4.50%	0.02%	0.01%	1.6367	0.02%
3	Common Equity	5,523,860,308	52.48%	41.50%	10.70%	5.61%	4.44%	1.6367	7.27%
4	Total Permanent Capital	$ 10,526,430,308	100.00%						
5	Short Term Debt	217,200,000		1.63%	1.73%		0.03%	1.0000	0.03%
6	Deferred Income Taxes	2,528,157,000		18.99%	0.00%		0.00%	1.0000	0.00%
	Job Develop, Investment Tax Credit								
7	Long-term Debt	18,715,407		0.14%	5.02%		0.01%	1.0000	0.01%
8	Preferred	140,650		0.00%	4.50%		0.00%	1.6367	0.00%
9	Common Equity	20,820,943		0.16%	10.70%		0.02%	1.6367	0.03%
10	Total Capitalization	$ 13,311,464,307		100.00%			6.38%		9.22%

Source: Ex. A-87 (AJD-10)

STATE OF MICHIGAN

COURT OF APPEALS

ATTORNEY GENERAL,

Appellant,

v

MICHIGAN PUBLIC SERVICE COMMISSION,

Appellee,

and

CONSUMERS ENERGY COMPANY,

Petitioner-Appellee.

UNPUBLISHED
April 30, 2015

No. 317434
Public Service Commission
LC No. 00-017087

MICHELLE RISON, ANN DEROUIN, MITCHELL DEROUIN, BILLIE J. PREKLESIMER, JOYCE HORNESS, MARCUS HORNESS, MIKE KEMPF, SANDY KEMPF, DAN MARTIN MILLS, CHERYL MCKINNEY, GLORIA GARDNER, KERRY KRENTZ, HEATHER WITKOWSKI, CHRISTINE HUNT, SCOTT BRASPENNINX, and PAM DAZEY,

Appellants,

v

MICHIGAN PUBLIC SERVICE COMMISSION,

Appellee,

and

CONSUMERS ENERGY COMPANY,

Petitioner-Appellee.

No. 317456
Public Service Commission
LC No. 00-017087

Before: O'CONNELL, P.J., and FORT HOOD and GADOLA, JJ.

PER CURIAM.

In these consolidated cases, the Attorney General and Michelle Rison, et al., appeal a June 28, 2013 order issued by the Michigan Public Service Commission (PSC) approving an application by Consumers Energy Company (Consumers Energy) for a rate increase to continue funding, among other things, its advanced metering infrastructure (AMI) program, and approving tariffs for customers who elect to opt-out of the AMI program. For the reasons below, we affirm the stipulation and order for the rate increases in Docket No. 317464, but because of the numerous issues raised on appeal in Docket No. 317456 concerning tariffs for customers who elect to opt-out of the AMI program, we remand those issues to the PSC and direct the PSC to conduct a contested case hearing on the opt-out tariff. We direct the PSC to issue a detailed opinion with sufficient facts and conclusions of law that allows this Court to review the entire scope of the unusual opt-out tariff.

I. BACKGROUND

Several years ago, Consumers Energy began implementing an AMI[1] program in Michigan. On November 4, 2010, the PSC issued an order in Case No. U-16191 that approved Consumers Energy's pilot AMI program, but required Consumers Energy to meet certain conditions, such as providing information on the benefits and costs of the program, before approving full deployment of the AMI program. In *In re Application of Consumers Energy Co to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued November 20, 2012 (Docket Nos. 301318 and 301381), this Court affirmed the PSC's decision regarding Consumers Energy's pilot AMI program. On June 7, 2012, the PSC issued an order in Case No. U-16794 authorizing Consumers Energy to proceed with Phase 2 of its AMI deployment program. In that case, the PSC adopted $44.8 million in expenditures for the AMI program in Consumers Energy's rate base.

On September 19, 2012, Consumers Energy filed an application requesting rate relief in the case underlying this appeal, Case No. U-17087, to cover, among other things, its ongoing investments associated with the AMI program. In addition, Consumers Energy sought approval of opt-out tariffs for customers who did not wish to participate in the AMI program. On October 19, 2012, an administrative law judge (ALJ) granted intervenor status to the Attorney General.

On May 7, 2013, the parties filed a settlement agreement in which they agreed to an annual rate increase of $89 million. However, in the agreement, the Attorney General reserved two issues for future resolution, including (1) a request to the PSC "to direct Consumers Energy to suspend the [AMI] program," and (2) an objection "to the amount of the 'opt-out' fee." The

[1] An AMI meter, also known as a smart meter, is capable of collecting near-real-time data on a customer's energy usage and reporting the data to the utility at frequent intervals. *In re Applications of Detroit Edison Co*, 296 Mich App 101, 114; 817 NW2d 630 (2012).

PSC entered an order on May 15, 2013, approving the settlement agreement. Thereafter, the Attorney General challenged the PSC's continued support of Phase 2 of Consumers Energy's AMI program and challenged Consumers Energy's application for approval of its opt-out tariffs.

In response, Consumers Energy argued that it prepared an updated business case analysis for its AMI program in March 2012, and that the analysis indicated a 20-year positive net present value (NPV) of $42 million for the AMI program. Consumers Energy noted that the Attorney General also sought suspension of its AMI program in Case Nos. U-16191 and U-16794 on the ground that the cost/benefit analysis used in each case was flawed, but that the PSC rejected the Attorney General's request in each case. The Attorney General argued that the PSC should suspend Consumers Energy's AMI program until a cost/benefit analysis showed that the program would bring value to customers. The Attorney General asserted that its analysis showed that the AMI program had a negative NPV, and that Consumers Energy's testimony regarding savings from the AMI program was speculative.

On June 28, 2013, the PSC issued an order approving Consumers Energy's continuation of the AMI program and approving Consumers Energy's opt-out tariffs. The Attorney General (Docket No. 317434) and Michelle Rison, et al. (Docket No. 317456)[2] now appeal from the PSC's June 28, 2013, order.

II. STANDARD OF REVIEW

The standard of review for PSC orders is narrow and well defined. Pursuant to MCL 462.25, all rates, fares, charges, classifications and joint rates, regulations, practices, and services prescribed by the PSC are presumed, prima facie, to be lawful and reasonable. *Mich Consol Gas Co v Pub Serv Comm*, 389 Mich 624, 635-636; 209 NW2d 210 (1973). A party aggrieved by an order of the PSC has the burden of proving by clear and satisfactory evidence that the order is unlawful or unreasonable. MCL 462.26(8). To establish that a PSC order is unlawful, the appellant must show that the PSC failed to follow a mandatory statute or abused its

[2] Appellants in Docket No. 317456 were not parties to the proceedings below. These appellants claim entitlement to an appeal as of right under MCL 462.26(1), which states the following:

> Except as otherwise provided . . . any common carrier or other party in interest, being dissatisfied with any order of the commission fixing any rate or rates, fares, charges, classifications, joint rate or rates, or any order fixing any regulations, practices, or services, may within 30 days from the issuance and notice of that order file an appeal as of right in the court of appeals. . . .

Appellants claim they are parties in interest under the statute because they are customers of Consumers Energy who will be required to pay tariffs under the opt-out program. The phrase "party in interest" in MCL 462.26(1) is undefined in the statute, and it is unclear whether this phrase permits any *person* with an interest in the proceedings to file an appeal as of right, or whether it requires that such a person first be a *party* to the proceedings to claim such an appeal. On remand, the PSC shall determine if these parties have standing to proceed below.

discretion in the exercise of its judgment. *In re MCI Telecom Complaint*, 460 Mich 396, 427; 596 NW2d 164 (1999). An order is unreasonable if it is not supported by the evidence. *Associated Truck Lines, Inc v Pub Serv Comm*, 377 Mich 259, 279; 140 NW2d 515 (1966).

A final order of the PSC must be authorized by law and must be supported by competent, material, and substantial evidence on the whole record. Const 1963, art 6, § 28. A reviewing court gives due deference to the PSC's administrative expertise and is not to substitute its judgment for that of the PSC. *Attorney General v Pub Serv Comm No 2*, 237 Mich App 82, 88; 602 NW2d 225 (1999). "Whether the PSC exceeded the scope of its authority is a question of law that we review de novo." *In re Complaint of Pelland against Ameritech Mich*, 254 Mich App 675, 682; 658 NW2d 849 (2003).

III. DOCKET NO. 317434

In Docket No. 317434, the Attorney General argues that the PSC erred in approving the continuation of Phase 2 of Consumers Energy's $750 million AMI program because the record lacked competent, material, and substantial evidence demonstrating that the costs of the AMI program outweighed its benefits. The PSC first argues that the Attorney General lacks standing to challenge the June 28, 2013, order in this case. A party must be aggrieved by a lower court's decision in order to have standing to bring an appeal from that decision. MCR 7.203(A); *Federated Ins Co v Oakland Co Rd Comm*, 475 Mich 286, 290-291; 715 NW2d 846 (2006). "To be aggrieved, one must have some interest of a pecuniary nature in the outcome of the case, and not a mere possibility arising from some unknown and future contingency." *Federated Ins Co*, 475 Mich at 291 (quotation marks and citation omitted).

MCL 462.26(1) provides that "any common carrier or other party in interest, being dissatisfied with any order of the commission fixing any rate or rates, fares, charges, classifications, joint rate or rates, or any order fixing any regulations, practices, or services, may within 30 days from the issuance and notice of that order file an appeal as of right in the court of appeals." The Attorney General gave notice of intervention and was granted intervenor status in this case below. The Attorney General had the statutory right to intervene to represent the interests of the people of the state, MCL 14.28, and he stated that he intervened because the case would affect rates paid by Consumers Energy's customers. The June 28, 2013, PSC order approved, among other things, opt-out tariffs for Consumers Energy's customers. Thus, the Attorney General was a party in interest with standing to appeal the order under MCL 462.26(1).

Although the Attorney General has standing to bring this appeal, we conclude that the stipulation to the $89 million increase forecloses any objection that the Attorney General has to the rate increase.

As part of Case No. U-17087 underlying this appeal, the Attorney General was permitted to contest Consumers Energy's requested rate increase associated with the 2013 through 2014 portion of Phase 2 of its AMI program. See MCL 462.26(1). However, we determine that the Attorney General, on appeal, may not contest the rate increase because the parties stipulated in the May 7, 2013, settlement agreement to an $89 million revenue increase that covered, in part, Consumers Energy's ongoing investments in its AMI program. The agreement stated the following:

> The Attorney General has requested the Commission to direct Consumers Energy to suspend the Advanced Metering Infrastructure ("AMI") program, and in the event the program continues, has objected to the amount of the "opt-out" fee. These issues are not resolved as part of this settlement. The parties request the Commission to address these issues based upon the initial and reply briefs filed pursuant to the schedule established by the Administrative Law Judge in this case. *The parties agree that the $89.0 million annual revenue increase and associated rates specified in this Settlement Agreement shall not be affected by the Commission's ruling on this issue.* . . . [Emphasis added.]

Because the Attorney General stipulated to the $89 million rate increase that covered, in part, the 2013 through 2014 portion of Phase 2 of Consumers Energy's AMI program, the Attorney General has not presented any issues warranting relief.

IV. DOCKET NO. 317456

A. AUTHORITY TO APPROVE AMI OPT-OUT PROGRAM

Appellant customers contend that the PSC lacked the statutory authority to impose an opt-out program on customers who do not wish to participate in the AMI program, and that the PSC should have considered an opt-in program instead. Because this issue was not raised below, we review the unpreserved claim for outcome-determinative plain error. *In re Application of Consumers Energy Co*, 278 Mich App 547, 568; 753 NW2d 287 (2008).

The PSC possesses only those powers conferred upon it by the Legislature, and thus has no authority to make management decisions on behalf of utilities. *Union Carbide Corp v Pub Serv Comm*, 431 Mich 135, 148-150; 428 NW2d 322 (1988) (holding that the PSC lacked authority to forbid the operation of a facility). However, under MCL 460.6(1), the PSC has broad authority to regulate reasonable rates for all public utilities. Within its ratemaking authority, "[t]he PSC has discretion to determine what charges and expenses to allow as costs of operation." *Ford Motor Co v Pub Serv Comm*, 221 Mich App 370, 375; 562 NW2d 224 (1997).

In this case, the PSC's June 28, 2013, order approved tariff rates for customers who elected either to retain a standard meter or to replace a transmitting AMI meter with a standard meter. The approved rates were based on the PSC's determination of the actual costs associated with maintaining equipment and services for customers with non-transmitting meters. A decision to impose charges and expenses based on a utility's costs of operation is well within the ratemaking authority of the PSC. *Ford Motor Co*, 221 Mich App at 375. Accordingly, the PSC did not exceed its statutory authority.

B. IMPOSITION OF FEES ON OPT-OUT CUSTOMERS

Appellant customers argue that the PSC's approval of the tariffs requiring customers who opt-out of the AMI program to pay a one-time charge of either $69.39 or $123.91 and a monthly charge of $9.72 was unjust, unreasonable, and unsupported by evidence in the record. At oral argument before this Court, the parties raised numerous arguments regarding whether the tariff amounts approved by the PSC represented the actual costs associated with continued use of analog meters, and whether any of these costs were already accounted for in the utility's rates.

Unfortunately, it appears that these issues were given only cursory analysis in the PSC lower court record. We conclude that the record on this issue is inadequate to support an informed decision by the Court at this time. Accordingly, we remand this issue to the PSC to conduct a contested case hearing on this significant issue.[3] The parties are entitled to present their positions, and the PSC shall issue a written opinion on its findings of fact and conclusions of law.

Docket No. 317434 is affirmed. Docket No. 317456 is affirmed in part, reversed in part, and remanded for further proceedings consistent with this opinion. We do not retain jurisdiction.

/s/ Peter D. O'Connell
/s/ Karen M. Fort Hood
/s/ Michael F. Gadola

[3] On remand, the PSC should clarify the purpose and nature of the opt-out tariff by addressing whether the tariff represents a reimbursement for costs of service, or whether the tariff constitutes something more akin to a tax, sanction, or penalty imposed upon customers who choose to opt out of the AMI program.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-17735

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Samantha O'Rourke, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on July 17, 2015, she served an electronic copy of the **"Initial Brief of Consumers Energy Company"** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein. She further states that she also served a hard copy of the same document to the Hon. Mark E. Cummins, Administrative Law Judge at the address listed in Attachment 1 by depositing the same in the United States mail in the City of Jackson, Michigan, with first-class postage thereon fully paid.

Digitally signed by Samantha O'Rourke
Date: 2015.07.17 16:50:18 -04'00'

Samantha O'Rourke

Subscribed and sworn to before me this 17th day of July, 2015.

Digitally signed by Tara L. Hilliard
Date: 2015.07.17 16:49:49 -04'00'

Tara L. Hilliard, Notary Public
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My Commission Expires: 09/12/20
Acting in the County of Jackson

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