January 24, 2012

Ms. Mary Jo Kunkle  
Executive Secretary  
Michigan Public Service Commission  
6545 Mercantile Way  
P.O. Box 30221  
Lansing, MI 48909

Re: Case No. U-16794 - In the Matter of the application of Consumer Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief

Dear Ms. Kunkle:

Enclosed for electronic filing in the above-captioned case, 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 also enclosed a Proof of Service showing electronic service upon the parties.

Sincerely,

Eric V. Luoma

cc: Hon. Sharon L. Feldman, ALJ  
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-16794

INITIAL BRIEF OF CONSUMERS ENERGY COMPANY

January 24, 2012
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>I.</td>
<td>INTRODUCTION AND OVERVIEW</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>A. Procedural Overview</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>B. Executive Summary/Overview of Company Requests</td>
<td>2</td>
</tr>
<tr>
<td>II.</td>
<td>TEST YEAR</td>
<td>4</td>
</tr>
<tr>
<td>III.</td>
<td>RATE BASE</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>A. Net Utility Plant</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>1. Distribution Capital Expenditures</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>a. Company’s Position</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>b. Areas of Dispute with Staff</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>c. Areas of Dispute with the Attorney General</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>2. Fossil and Hydro Generation Capital Expenditures</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>a. Company’s Position</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>b. Areas of Dispute with Staff</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td>c. Areas of Dispute with the Attorney General</td>
<td>11</td>
</tr>
<tr>
<td></td>
<td>d. Areas of Dispute with NRDC/MEC</td>
<td>14</td>
</tr>
<tr>
<td></td>
<td>e. Appeal of Striking of Portions of Company Witness Popa’s Rebuttal Testimony</td>
<td>16</td>
</tr>
<tr>
<td></td>
<td>3. Energy Supply Capital Expenditures</td>
<td>19</td>
</tr>
<tr>
<td></td>
<td>a. Company’s Position</td>
<td>19</td>
</tr>
<tr>
<td></td>
<td>4. Business Technology Solutions “BTS” Capital Expenditures</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td>a. Company’s Position</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td>b. Areas of Dispute with the Attorney General</td>
<td>21</td>
</tr>
<tr>
<td></td>
<td>5. Smart Grid/Advanced Metering Infrastructure (“SG/AMI”) Capital Expenditures</td>
<td>23</td>
</tr>
<tr>
<td></td>
<td>b. Phase 2 (2011–2013)</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td>d. IT System Development</td>
<td>27</td>
</tr>
<tr>
<td></td>
<td>e. Capital Expenditures</td>
<td>27</td>
</tr>
</tbody>
</table>
TABLE OF CONTENTS
(Continued)

<table>
<thead>
<tr>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>f. Cost/Benefit Analysis.................................................................28</td>
</tr>
<tr>
<td>(i) Staff’s Position on SG/AMI and a “Cost Recovery Cap”.............28</td>
</tr>
<tr>
<td>g. Response to the Attorney General’s Position..............................30</td>
</tr>
<tr>
<td>(i) Attorney General’s Opinion of Phase 1 Pilot Results...............30</td>
</tr>
<tr>
<td>(ii) Attorney General’s Opinion of Cost/Benefit Model.................32</td>
</tr>
<tr>
<td>6. Company Response Regarding Staff’s Plant-In-Service and Plant Held for Future Use Test Year Balances.................................34</td>
</tr>
<tr>
<td>7. CWIP..............................................................................................35</td>
</tr>
<tr>
<td>8. Clean Coal Plant...........................................................................37</td>
</tr>
<tr>
<td>9. Accumulated Provision for Depreciation.......................................37</td>
</tr>
<tr>
<td>B. Working Capital............................................................................38</td>
</tr>
<tr>
<td>1. Working Capital Methodology and Calculation............................38</td>
</tr>
<tr>
<td>2. Response Regarding Staff’s PeopleCare Adjustment....................40</td>
</tr>
<tr>
<td>C. Total Rate Base............................................................................40</td>
</tr>
<tr>
<td>IV. RATE OF RETURN AND CAPITAL STRUCTURE.............................41</td>
</tr>
<tr>
<td>A. Introduction and Identification of Areas of Disagreement Between the Company and Staff.........................................................41</td>
</tr>
<tr>
<td>B. Test Year Capital Structure............................................................42</td>
</tr>
<tr>
<td>1. Capital Structure Component Balances........................................43</td>
</tr>
<tr>
<td>a. Common Equity Balance .........................................................43</td>
</tr>
<tr>
<td>b. Long-Term Debt Balance..........................................................43</td>
</tr>
<tr>
<td>c. Short-Term Debt Balance.........................................................43</td>
</tr>
<tr>
<td>d. Deferred Federal Income Tax Balance.......................................44</td>
</tr>
<tr>
<td>e. Other Capital Structure Balances.............................................44</td>
</tr>
<tr>
<td>2. The Attorney General’s Proposal to Impute CMS Energy’s Capital Structure Should Be Rejected As It Was When Raised In Case Nos. U-15645 and U-15986.........................................................44</td>
</tr>
<tr>
<td>C. Cost Rates....................................................................................46</td>
</tr>
<tr>
<td>1. Return on Common Equity..........................................................47</td>
</tr>
<tr>
<td>a. Introduction and Summary of Position – Reducing the Currently Authorized 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.........................47</td>
</tr>
<tr>
<td>b. Applicable Principles ..............................................................49</td>
</tr>
</tbody>
</table>
### TABLE OF CONTENTS

(Continued)

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>c. Proxy Group Selection Criteria and Investor Risk Perceptions</td>
<td>50</td>
</tr>
<tr>
<td>d. Analytical Methodologies and Conclusions</td>
<td>52</td>
</tr>
<tr>
<td>e. Additional Risk Considerations</td>
<td>56</td>
</tr>
<tr>
<td>(i) Michigan Risk Versus National Risk</td>
<td>56</td>
</tr>
<tr>
<td>(ii) Consumers Energy Risk Versus Detroit Edison Risk</td>
<td>57</td>
</tr>
<tr>
<td>(iii) Investor ROE Expectations</td>
<td>59</td>
</tr>
<tr>
<td>(iv) Risk Aversion and Cost of Equity</td>
<td>59</td>
</tr>
<tr>
<td>f. Additional Response to Attorney General</td>
<td>60</td>
</tr>
<tr>
<td>g. Return on Equity Conclusion and Request for Relief</td>
<td>61</td>
</tr>
<tr>
<td>2. Long-Term Debt Cost</td>
<td>62</td>
</tr>
<tr>
<td>3. Short-Term Debt Cost</td>
<td>62</td>
</tr>
<tr>
<td>4. Other Cost Rates</td>
<td>62</td>
</tr>
<tr>
<td>D. Overall Rate of Return</td>
<td>63</td>
</tr>
<tr>
<td>V. ADJUSTED NET OPERATING INCOME</td>
<td>63</td>
</tr>
<tr>
<td>A. Jurisdictional Revenues and Sales Forecast</td>
<td>63</td>
</tr>
<tr>
<td>1. Response to the Attorney General</td>
<td>64</td>
</tr>
<tr>
<td>2. Response to NRDC/MEC</td>
<td>66</td>
</tr>
<tr>
<td>B. Fuel, Purchase and Interchange Expense</td>
<td>66</td>
</tr>
<tr>
<td>C. Other O&amp;M Expense</td>
<td>67</td>
</tr>
<tr>
<td>1. Electric Distribution O&amp;M Expense</td>
<td>67</td>
</tr>
<tr>
<td>a. Company’s Position</td>
<td>67</td>
</tr>
<tr>
<td>b. Areas of Dispute with Staff</td>
<td>70</td>
</tr>
<tr>
<td>c. Areas of Dispute with the Attorney General</td>
<td>72</td>
</tr>
<tr>
<td>d. Areas of Dispute with MCAA</td>
<td>72</td>
</tr>
<tr>
<td>2. Fossil and Hydro Generation O&amp;M Expense</td>
<td>73</td>
</tr>
<tr>
<td>a. Company’s Position</td>
<td>73</td>
</tr>
<tr>
<td>b. Areas of Dispute with Staff</td>
<td>74</td>
</tr>
<tr>
<td>c. Areas of Dispute with the Attorney General</td>
<td>76</td>
</tr>
<tr>
<td>d. Areas of Dispute with NRDC/MEC</td>
<td>77</td>
</tr>
<tr>
<td>3. Energy Supply O&amp;M Expense</td>
<td>78</td>
</tr>
<tr>
<td>a. Company’s Position</td>
<td>78</td>
</tr>
<tr>
<td>4. Corporate Service O&amp;M Expense</td>
<td>78</td>
</tr>
<tr>
<td>a. Company’s Position</td>
<td>78</td>
</tr>
</tbody>
</table>
TABLE OF CONTENTS
(Continued)

<table>
<thead>
<tr>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Areas of Dispute with Staff</td>
</tr>
<tr>
<td>c. Areas of Dispute with the Attorney General</td>
</tr>
<tr>
<td>5. Uncollectible Expense</td>
</tr>
<tr>
<td>a. Company’s Position</td>
</tr>
<tr>
<td>b. Areas of Dispute with Staff</td>
</tr>
<tr>
<td>c. Areas of Dispute with the Attorney General</td>
</tr>
<tr>
<td>6. Injuries and Damages Expense</td>
</tr>
<tr>
<td>a. Company’s Position</td>
</tr>
<tr>
<td>b. Areas of Dispute with Staff</td>
</tr>
<tr>
<td>7. BTS O&amp;M Expenses</td>
</tr>
<tr>
<td>a. Company’s Position</td>
</tr>
<tr>
<td>b. Areas of Dispute with Staff</td>
</tr>
<tr>
<td>c. Areas of Dispute with the Attorney General</td>
</tr>
<tr>
<td>8. Employee Benefits</td>
</tr>
<tr>
<td>a. The Company and Staff Are in Agreement</td>
</tr>
<tr>
<td>b. Areas of Dispute with the Attorney General</td>
</tr>
<tr>
<td>9. SG/AMI O&amp;M Expense Items</td>
</tr>
<tr>
<td>a. Company’s Position</td>
</tr>
<tr>
<td>D. Depreciation and Amortization Expense</td>
</tr>
<tr>
<td>E. Taxes</td>
</tr>
<tr>
<td>1. Property Tax</td>
</tr>
<tr>
<td>2. Federal, Michigan, and Local Income Taxes</td>
</tr>
<tr>
<td>3. Medicare Part D Subsidy Tax Issues</td>
</tr>
<tr>
<td>F. Allowance for Funds Used during Construction (&quot;AFUDC&quot;)</td>
</tr>
<tr>
<td>G. Calculation of Adjusted Net Operating Income</td>
</tr>
<tr>
<td>VI. OTHER REVENUE AND ACCOUNTING ISSUES</td>
</tr>
<tr>
<td>A. Revenue Decoupling Mechanism/Revenue Tracker Proposal</td>
</tr>
<tr>
<td>B. Uncollectible Expense Tracking Mechanism</td>
</tr>
<tr>
<td>1. Company’s Position</td>
</tr>
<tr>
<td>C. Electric Choice Sales Tracker Proposal</td>
</tr>
<tr>
<td>D. Recovery of Clean Coal Plant Expenditures</td>
</tr>
<tr>
<td>1. Clean Coal Plant Costs and Prudence</td>
</tr>
<tr>
<td>2. Accounting for Clean Coal Plant Expenditures</td>
</tr>
</tbody>
</table>
### TABLE OF CONTENTS (Continued)

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>3. Ratemaking Recovery of Clean Coal Plant Expenditures</td>
<td>112</td>
</tr>
<tr>
<td>4. Responses to Staff, ABATE, and MCAA A Witnesses</td>
<td>115</td>
</tr>
<tr>
<td>E. SG/AMI Accounting Clarification Request</td>
<td>118</td>
</tr>
<tr>
<td>F. Response Regarding MCAA A’s DOE Liability Issues</td>
<td>121</td>
</tr>
<tr>
<td>G. Response to NRDC/MEC’s Line Loss Issues</td>
<td>121</td>
</tr>
<tr>
<td>H. Response to the Attorney General’s Rate Case Expense Proposal</td>
<td>123</td>
</tr>
<tr>
<td>VII. REVENUE DEFICIENCY CALCULATION</td>
<td>124</td>
</tr>
<tr>
<td>VIII. COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES</td>
<td>124</td>
</tr>
<tr>
<td>A. Cost of Service</td>
<td>124</td>
</tr>
<tr>
<td>B. Rate Design and Tariff Issues</td>
<td>125</td>
</tr>
<tr>
<td>1. Design of Rate GPD</td>
<td>126</td>
</tr>
<tr>
<td>2. Base PSCR Costs</td>
<td>128</td>
</tr>
<tr>
<td>3. Rate GSG-2</td>
<td>128</td>
</tr>
<tr>
<td>4. Power Factor Adjustment</td>
<td>129</td>
</tr>
<tr>
<td>5. Skewing and Discount Allocations</td>
<td>130</td>
</tr>
<tr>
<td>6. System Access Charge</td>
<td>130</td>
</tr>
<tr>
<td>7. Proposed Separate Municipal Rate Design</td>
<td>131</td>
</tr>
<tr>
<td>8. Changes to Metal Melting Pilot Program</td>
<td>131</td>
</tr>
<tr>
<td>IX. CONCLUSION</td>
<td>131</td>
</tr>
<tr>
<td>APPENDICES A THROUGH E</td>
<td></td>
</tr>
</tbody>
</table>
INITIAL BRIEF OF CONSUMERS ENERGY COMPANY

I. INTRODUCTION AND OVERVIEW

A. Procedural Overview

On June 10, 2011, Consumers Energy Company (“Consumers Energy” or “the Company”) filed its application in this case, seeking an increase in its electric rates sufficient to produce additional revenues in the approximate annual amount of $195 million. This request has subsequently been reduced to $181 million. See Appendix A. In its application, the Company indicated that, for purposes of calculating its revenue requirement in this case, it has updated the sales levels adopted by the Commission in Case No. U-15645.

Pursuant to MCL 460.6a(1), absent an order from the Commission that either prevents or delays self-implementation, Consumers Energy would have been allowed to self-implement up to the full amount of its proposed rate increase on December 8, 2011. Following a hearing held on November 22, 2011, the Commission issued an order on December 6, 2011, that limited the Company to implement a maximum rate increase of no more than $118 million. That increase went into effect on December 8, 2011.

Evidentiary hearings in this case then commenced December 13, 2011, and were concluded December 19, 2011. Pursuant to the schedule established by Administrative Law

B. Executive Summary/Overview of Company Requests

Mr. Ronn J. Rasmussen provides an overview of the Company’s request in this case. 3 TR 90-98. The $181 million of annual rate relief requested by the Company is primarily driven by two major categories. The first category is the Company’s continued investment in Michigan. Over the next five years the Company plans to invest more than $6 billion in Michigan to maintain and improve utility infrastructure, increase the amount of energy generated from renewable resources and insure customers receive the quality of service they expect. Approximately $145 million of the requested rate relief is related to growth in rate base resulting from these investments. This includes $20 million of revenue requirement that arises from a change in depreciation rates approved in Case No. U-16054. The $145 million is split as follows: 35% is related to required environmental compliance expenditures; 55% is related to generation and distribution reliability expenditures; and 10% is related to Smart Grid investments.

The second major category impacting the requested rate relief is the update to electricity sales, including the impact of sales associated with retail open access (“ROA”). This update accounts for approximately $50 million of the requested rate relief. Approximately 92% is driven by increased retail open access sales levels with the remainder being driven by non-ROA related reductions in bundled sales.

This filing includes a reduction in total O&M expense of $34 million when compared to the level of O&M approved in Case No. U-16191. These reductions in O&M expense are a result of: (1) focusing capital investments on projects that improve customer
service and reliability while reducing O&M expense; (2) productivity improvements; (3) benefits from implementation of SAP; and (4) savings achieved through collective bargaining agreement improvements. The Company proposes increases in forestry O&M to improve customer reliability and requests that an increase in uncollectible expenses be recognized that is due to a reduction in Low Income Home Energy Assistance Program (“LIHEAP”) funding and other economic conditions.

The Staff’s position in this case indicates an initial revenue deficiency of approximately $38.8 million. Appendices A-E attached to this Brief show, in summary form, the Company’s initial position, the MSPC Staff’s as-filed position, the Company’s Brief position, and the variance between the Company’s and Staff’s positions.

The Company has some major concerns with some of the Staff’s positions in this case. The Staff’s positions of greatest concern to Consumers Energy are:

- Staff witness Jill Rusnak’s recommendation to eliminate environmental capital expenditures that are needed to comply with existing state and federal clean air act rules. This has a significant impact on the level of Construction Work in Progress (“CWIP”). See Appendix B, line 4.

- Staff’s failure to update Working Capital to reflect the same starting point as was done for Plant-in-Service, Plant Held for Future Use, and CWIP components of Rate Base. See Appendix B, line 10.

- Staff’s failure to properly implement the revised depreciation rates approved in Case No. U-16054. See Appendix C, line 4.

- Staff witness Jill Rusnak’s recommendation to disallow major maintenance and investment expenditures necessary to continue safe operations at the Company’s seven smaller generating units up to the date they are mothballed. See Appendix D, line 4 (impact carried over on Appendix C, line 3).

- Staff witness Charles Reasoner’s recommendation to exclude funding for distribution system reliability investments (see Appendix B, line 4) and limiting forestry expense to a level that does not allow improved reliability. See Appendix D, line 2 (impact carried over on Appendix C, line 3).
- Staff witnesses Jill Rusnak’s and Daniel Birkam’s recommendation to not allow recovery of clean coal plant project costs. Cancellation of the project occurred on December 2, 2011, and recovery of these prudent costs is appropriate. See Appendix B, line 5 (rate base) and Appendix C, line 5 (amortization).

- Staff’s recommendation concerning return on equity (“ROE”), which is extremely low when compared to ROEs recently approved by the Commission. See Appendix E, pp. 1-2, line 3.

- Staff’s argument against a tracker for uncollectible expense despite the volatility of this expense and the effect of regulatory lag. Coupled with Staff’s failure to adopt a realistic and reasonable level of uncollectibles expense (see Appendix D, line 14, impact carried over to Appendix C, line 3), this has a major negative impact.

The Company in this Brief addresses each one of the above issues in detail along with other issues raised by Staff and intervenors and relies upon the record and evidence in support of its requested rate relief.

II. TEST YEAR

In each rate case, a Test Year must be selected. In this regard, it should be noted 2008 PA 286 specifically provides for the use of “projected” Test Years in setting utility rates. MCL460.6a(1). Consumers Energy used a projected 12-month Test Year ending September 30, 2012 for determining final rate relief. 3 TR 159, 168. Consumers Energy’s witness Erin A. Rolling testified that using a historical Test Year for final relief would be inadequate because it would ignore known and measurable changes including, among other things: 1) the significant investment and growth in rate base that the Company has experienced in 2011 and will experience in the first nine months of 2012; and 2) changes in operating costs including increases in forestry activities and uncollectible expenses and decreases in employee benefits, and rate of return changes. 3 TR 159. In developing projected Test Year data, Consumers Energy began with a 2010 historical period, which was then adjusted to reflect updated sales and projections of investments, expenses, and revenues. 3 TR 177-179.
III. RATE BASE

A. Net Utility Plant

1. Distribution Capital Expenditures

   a. Company’s Position

   Company witness James R. Anderson, Executive Manager of Electric Asset Management, testified concerning the Company’s distribution plant-related capital expenditures. At 4 TR 861-867 and Exhibit A-13 (JRA-2), Mr. Anderson 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. Anderson testified, the Company is projecting capital expenditures for distribution programs in the amount of $289,222,000 in 2010; $318,403,000 in 2011; and $244,339,000 for the 9-months ended September 30, 2012. Exhibit A-13 (JRA-2), line 8; 4 TR 861-867.

   There are seven major programs within the Electric Distribution Capital Expenditures. 4 TR 861. As shown on Exhibit A-13 (JRA-2) lines 1-7, 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. 4 TR 861. Each of these programs are explained and supported in detail in Mr. Anderson’s testimony, 4 TR 861-867. These distribution capital expenditures in conjunction with the O&M expenses addressed elsewhere in this Brief address the three leading causes of customer outages on the Company’s electric system, namely tree related, equipment failures, and lightning/weather. 4 TR 864-865. The goal is to improve system reliability and to enhance customer satisfaction through a reduction of customer outages. 4 TR 865.
b. **Areas of Dispute with Staff**

Consumers Energy requests the Commission reject Staff witness Reasoner’s proposed total Reliability capital expenditures of $67,299,750 ($7,477,750 average per month) for the 9-months ended September 30, 2012, an amount that is $9,333,250 less than requested by the Company (for the 9-months ended September 30, 2012). 4 TR 879. The amount proposed by Mr. Reasoner is the same amount of Reliability capital expenditures on a monthly basis as the Company spent in 2011. 4 TR 879. Mr. Reasoner explained he is not supportive of increasing the Capital expenditure amount until the Company can demonstrate improved distribution reliability associated with its Reliability capital expenditures. 4 TR 879.

While Mr. Reasoner’s proposal does represent an increase over historical spending patterns, the Company’s Reliability capital request includes additional funding over the 2011 level projected by the Company for deteriorated pole replacements (as found through a more rigorous pole inspection program) and increased line rehabilitation associated with repetitive outage and metropolitan system improvements. 4 TR 879. All of these additional capital expenditures will result in improved system reliability to the benefit of customers as they target areas that cost effectively improve system reliability. 4 TR 879.

It must be remembered that reliability spending increases do not necessarily immediately improve overall system reliability metrics in direct proportion as Mr. Reasoner implies in his testimony. 4 TR 779-880. Mr. Anderson testified that the amount of money requested by the Company allows for work on 1%-2% of the electric distribution system, an effective cycle of 50-100 years. Thus, it is not reasonable to expect the Company’s overall system reliability performance to improve if spending is kept at or near the historic levels. 4 TR 882. Although localized capital expenditures are highly effective at addressing poor performing portions of the system, overall system reliability metrics are also impacted by the
size, age, condition, and performance of the portions of the electric distribution system the Company has not worked on or improved in a given year. 4 TR 880.

Additional expenditures in the Reliability capital program as requested by the Company are critical to improving the Company’s overall electric system reliability. 4 TR 880. According to Mr. Anderson, equipment failures are the number two cause of outages on the Company’s electric distribution system, causing approximately 19% of customer interruptions from 2006-2010. 4 TR 880. The Company thus requests the Commission grant the Reliability capital at the level requested by the Company.

c. **Areas of Dispute with the Attorney General**

Consumers Energy requests the Commission reject Attorney General witness Sebastian Coppola’s proposed total Reliability capital expenditures of $67,299,750 ($7,477,750 average per month) for the 9-months ended September 30, 2012, an amount that is $9,333,250 less than requested by the Company (for the 9-months ended September 30, 2012). Similarly to Staff witness Reasoner, Mr. Coppola proposes the same amount of Reliability capital expenditures on a monthly basis as the Company spent in 2011. 4 TR 886-887. The arguments provided above to Mr. Reasoner’s proposal also apply to Mr. Coppola’s proposal. In addition, when relying on historical expenditures, both Mr. Coppola and Mr. Reasoner ignore the fact historic expenditures have not allowed the Company to keep up with the normal deterioration of a large base of assets in the field. 4 TR 887. Therefore, Consumers Energy requests the Commission reject the Attorney General’s proposed reduction to the Company’s Reliability capital investment.

Mr. Coppola also proposes a $2 million reduction to the Company’s Electric Business Services Program capital. 4 TR 887; 4 TR 706. Mr. Coppola claims the spending level should remain at a historical spending level. However, as explained by Mr. Anderson, the
expenditures in this area are very volatile with non-historical fluctuations caused by planned and emergent facilities projects and fleet investments, thus a historical spending number is not appropriate as it would not include any non-historical planned or expected projects or investments. 4 TR 888. The specifics of the planned or expected expenditures were detailed by Mr. Anderson in his testimony at 4 TR 867. The Commission should reject Mr. Coppola’s proposed reduction.

2. **Fossil and Hydro Generation Capital Expenditures**

   a. **Company’s Position**

   Company witness David B. Kehoe, Director of Staff Electric Generation, testified concerning Consumers Energy’s Fossil and Hydro Generation Capital Expenditures. At 6 TR 1316-1326 and Exhibit A-29 (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 $200,594,000 in 2009; $247,177,000 in 2010; $244,464,000 in 2011; and $355,782,000 for the first 9-months of 2012. 6 TR 1320.

   Mr. Kehoe testified compliance with the Clean Air Act (“CAA”) and maintaining plant reliability are the major drivers of capital expenditures for the generating plants. 6 TR 1316. Mr. Kehoe provides a detailed explanation of both categories of capital expenditures at 6 TR 1320-1326. 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 1326. 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. 6 TR 1326.
Many of the capital expenditures in fossil generation are related to CAA compliance and are thus not discretionary. 6 TR 1326. The Company is actively working on mercury and PM2.5 controls to reduce emissions and meet state regulations. 6 TR 1326. By balancing the uncertainties of constantly evolving regulations, and recognizing the immaturity of the technological solutions, the Company has effectively managed the risk and uncertainties in CAA compliance. 6 TR 1326.

The early decision to implement plant combustion modifications and switch to western coal has allowed the Company to reduce emissions, reduce fuel costs, and approach post-combustion controls in a more deliberate manner. 6 TR 1326. While plant modifications are the most important part of the Company’s balanced approach, they are not the only option as the Company can rely on the existing emission markets to supplement its compliance strategy. 6 TR 1326. This balanced approach is one of the strengths of the Company’s strategy. 6 TR 1326. The Company’s resources are allocated to provide safe, reliable, and environmentally compliant generation for customers. 6 TR 1326.

b. Areas of Dispute with Staff

Consumers Energy requests the Commission reject Staff witness Rusnak’s proposal to adjust capital expenditures at the smaller generating plants, namely J.R. Whiting units 1 through 3 and B.C. Cobb units 4 and 5. 6 TR 1343. If Ms. Rusnak’s proposal to reduce capital expenditures for the Whiting and Cobb plants by $16.806 million (5 TR 1165) was adopted, the Company would be unable to safely and reliably operate the smaller generating plants. 6 TR 1343-1344.

As discussed elsewhere in this Brief, on December 2, 2011, Consumers Energy announced plans that provide for continued operation of the Company’s seven smallest coal-fired units through December 31, 2014 – at which time they will be “mothballed.” 6 TR 1341. The
level of proposed capital (and O&M) expenditures requested in this proceeding is not affected by
the plan to mothball the seven small generating units. 6 TR 1342. The Company’s filing in this
case only seeks recovery of the capital (and O&M) required to safely operate these plants and
comply with existing environmental regulations until the planned mothballing in 2015. 6 TR 1342.
Consumers Energy is not seeking recovery of costs that contemplate operation
beyond that date. 6 TR 1342.

Consumers Energy also requests the Commission reject Staff witness Rusnak’s
proposal to adjust test period capital expenditures related to PM2.5, Mercury, Section 316b and
RCRA and Other Environmental expenditures by $290.1 million (5 TR 1170). Ms. Rusnak’s
proposal is based on her mistaken belief these regulations are proposed and not yet final and
therefore remain uncertain. 6 TR 1440. In fact the vast majority of the capital expenditures
included in this case are for compliance with regulations that are final and certain. 6 TR 1440.
For any environmental rules where uncertainty does exist, the Company has minimized the level
of expenditures to the maximum degree possible, while still maintaining the ability to achieve
compliance when the rules do become final and certain. 6 TR 1440.

As an example, one of the adjustments recommended by Ms. Rusnak is to the
capital expenditures identified on Exhibit A-29 (DBK-4), line 13, labeled PM2.5. 6 TR 1440.
These expenditures are for the JH Campbell and DE Karn Plants related to reduction of NOx and
SO2, which are precursors of PM2.5. 6 TR 1440. These pollutants are currently regulated under
the Clean Air Interstate Rule (CAIR) that has been in effect since 2009. 6 TR 1440.

Another example is the adjustment recommended by Ms. Rusnak to the capital
expenditures identified on Exhibit A-29 (DBK-4), line 14, labeled Mercury. 6 TR 1441. These
expenditures are related to reduction of mercury at the JH Campbell and DE Karn Plants.
6 TR 1441. Mercury is currently regulated under the Michigan Mercury Rule which was finalized on October 16, 2009. 6 TR 1441.

In short, Consumers Energy has a well thought out, comprehensive plan to comply with all environmental regulations, a plan detailed in the testimony of Company witness Nancy A. Popa, 6 TR 1438-1450. If Ms. Rusnak’s proposed reductions are adopted by the Commission, the Company would be unable to recover the costs required to safely and reliably operate the smaller generating plants and meet current environmental regulations at many of its generating plants. 6 TR 1343-1344; 6 TR 1443-1445. Staff’s proposals to reduce test year fossil and hydro capital expenditures by $306.906 million should be rejected. The effect of including these expenditures in the development of test year utility plant is shown on Appendix B in note 3.

c. Areas of Dispute with the Attorney General

Consumers Energy requests the Commission reject Attorney General witness Coppola’s recommendation to reduce capital expenditures by $6.8 million for upgrades on combustion turbine units, $62.1 million for work at the Ludington Plant, and an additional 20% reduction to all capital projects. Each of his recommendations is addressed below.

Mr. Coppola’s first recommendation is to eliminate $6.8 million for upgrades to the combustion turbine units, excluding the Zeeland Plant. 6 TR 1349. However, Consumers Energy is not proposing to spend $6.8 million in capital investments and upgrades on combustion turbine units, and the Company is unaware as to any basis for this statement by Mr. Coppola. 6 TR 1349. The Commission should not adopt Mr. Coppola’s recommendation to eliminate $6.8 million from the Company’s forecasted capital expenditures as no evidence supports this claim. 6 TR 1349.
Mr. Coppola’s second recommendation is to eliminate any capital expenditures associated with the Ludington Plant including the $50.2 million forecasted in page 1 of Exhibit A-29 (DBK-4) for 2011 and 9-months ending September 2012 and actual expenditures incurred from 2007 to 2010 in the amount of $1.9 million as shown in Exhibit AG-20.\(^1\) 6 TR 1349. Mr. Coppola bases this recommendation on his lack of understanding as to why the monthly utilization rate of the Ludington Plant is approximately 20%.

As noted in the testimony of Mr. Kehoe, Consumers Energy and Detroit Edison will invest $800 million over six years to upgrade and lengthen the life of the Ludington Pumped Storage Facility. 6 TR 1350. The upgrades will improve the plant’s efficiency, increase its role in support of clean-energy sources from Michigan, ensure the plant will continue to produce low-cost, reliable electricity to customers during peak periods and reduce future maintenance expenses. 6 TR 1350. The amounts Mr. Coppola recommends be disallowed in this case represent the initial investments for this long-term project.

The utilization rate is less than 20% because Ludington is a pumped storage facility. 6 TR 1350. Mr. Coppola fails to recognize pumped storage facilities are fundamentally different than base-load units with very high utilization. 6 TR 1351. In a pumped storage facility, water is pumped uphill at night in order to produce power during peak periods. 6 TR 1351. Since no mechanical system is 100% efficient (pumped storage facilities are approximately 70% efficient) the plant must be pumped approximately 40% longer than it can generate electricity. 6 TR 1351. This leads to a maximum theoretical utilization rate of about 40%. 6 TR 1351. Excluding weekends, when Ludington is typically not used because the daily system peak demand is lower, and excluding the time necessary to switch the plant from

\(^1\) Mr. Coppola recommends a total amount of capital expenditures to be disallowed from the projected rate base with regard to the Ludington project to be $62.1 million. 6 TR 1349.
pumping to generating further reduces the utilization number. 6 TR 1351. The utilization of the Ludington Plant is in no way reflective of its value to the customers of Consumers Energy and Detroit Edison and, in fact, the Ludington Plant upgrade has a present value to Consumers Energy’s customers of $726 million (the value to Detroit Edison’s customers is comparable). 6 TR 1351.

The Commission should not adopt Mr. Coppola’s recommendation to eliminate funding for the Ludington Plant’s upgrade. The upgrades will improve the Ludington Plant’s efficiency, increase its role in support of clean-energy sources for Michigan, ensure the Ludington Plant will continue to produce low-cost, reliable electricity to customers during peak periods and reduce future maintenance expenses. 6 TR 1351.

Mr. Coppola’s last recommendation is for an overall 20% reduction to all capital expenditures based on his analysis of past spending on the generating plants. 6 TR 1352. Mr. Coppola fails to identify any project or project expenditure included in the Company’s forecast that is questionable or that should be specifically disallowed. 6 TR 1352.

Mr. Kehoe explained in his testimony why 2010 capital expenditures were less than projected. 6 TR 1352. According to Mr. Kehoe, actual capital expenditures in 2010 were less than projected primarily due to changes in the outage schedule (specifically Karn 2 and Campbell 1) and delays in the engineering of the Karn spray dry absorber. 6 TR 1352. Mr. Coppola is mistaken regarding capital expenditures for 2011 as he incorrectly annualizes a preliminary figure for 2011 ($158.2 million) rather than evaluating the cost of actual planned projects and when in the year the projects were planned to commence. 6 TR 1353.

The Commission should not adopt Mr. Coppola’s proposal to reduce capital expenditures by 20% because that proposal fails to conduct any analysis or evaluation of what
projects are actually needed. Consumers Energy anticipates capital expenditures based on the analysis of the need for and timing of specific projects. An approach, like Mr. Coppola’s, that simply relies upon prior expenditure levels fails to take a serious look as what is actually required to maintain these generating plants. 6 TR 1353. Furthermore, Mr. Coppola’s proposal fails to account for the work scheduled to be performed and the expenses that will be incurred. 6 TR 1352.

d. **Areas of Dispute with NRDC/MEC**

Consumers Energy requests the Commission reject NRDC/MEC witness Patricia H. Richards’ recommendation to reduce capital expenditures for investments that she mistakenly believes are being made to meet the Federal Regulation(s) EGU MACT/CSAPR and opines are speculative and not for the benefit of customers.

The first error Ms. Richards has made is basing her opinion on her misunderstanding that the capital investments at each plant are being made to meet EGU MACT/CSAPR. 6 TR 1445. In fact, the environmental expenditures identified in Exhibit A-29 (DBK-4), lines 13 through 14, are necessary to meet the existing Michigan Mercury Rule and the CAIR, both of which are final rules. 6 TR 1445-1446. Some of these investments will additionally contribute to achieving compliance with EGU MACT/CSAPR when those regulations become final, but the investments are necessary regardless of the effective dates of the EGU MACT/CSAPR regulations.² 6 TR 1445-1446.

Ms. Richards additionally mistakenly opines that Company projections in the rate case appear “speculative” in nature due to the uncertainty in the timing of the regulation.

² Specifically, all fabric filters being installed are needed to achieve compliance with the Michigan Mercury Rule (an existing rule), and will also play a part in achieving compliance with other federal rules such as NAAQS and EGU MACT/CSAPR. In addition, all Spray Dry Absorbers (“SDAs”) being installed will play a part in meeting the CAIR (an existing rule) as well as anticipated EGU MACT/CSAPR/NAAQS. 6 TR 1446.
6 TR 1446. In order to understand the Company’s environmental compliance efforts, it is necessary to tie expenditures to specific regulations. 6 TR 1446. Even though some spending prior to a regulation being promulgated is prudent, in this rate case, the vast majority of all of the expenditures identified are tied to existing regulations that are final. 6 TR 1446. Ms. Richards’ claim these expenditures appear “speculative” is incorrect; they are needed to comply with existing effective regulations. 6 TR 1447.

Ms. Richards also mistakenly alleges Consumers Energy has not demonstrated the capital expenditures included in this case for the Campbell, Karn, Cobb, and Weadock units are an “accruing benefit to the customer.” 6 TR 1449. As testified to by Mr. Kehoe at 6 TR 1326, these expenditures are benefiting customers. The environmental expenditures are required by law and are thus not discretionary. 6 TR 1449. Compliance with the laws and regulations is necessary for continued operation of the generating assets which provide great value to customers by continuing to utilize a largely depreciated asset to provide electricity to customers. 6 TR 1449. The Company has focused its environmental compliance investments on final regulations, and on the largest five coal-fired units. 6 TR 1449. The investments included in this case never included major environmental compliance expenditures for the Company’s seven smaller coal-fired units. 6 TR 1449. The environmental expenditures included in this case are an important part of the Company’s efforts to meet all applicable environmental requirements in the most cost-effective manner. 6 TR 1449-1450. In addition to being necessary to comply with federal and state law, these investments will decrease the environmental impact of electricity production, thus improving the quality of life for customers.3 6 TR 1450.

---

3 To date emissions of nitrogen oxides and sulfur dioxide have been reduced approximately 60%. Upon completion of our compliance plan, emissions will be reduced by 90%. 6 TR 1450.
The Commission should reject Ms. Richards’ suggestions regarding capital expenditures due to the errors and mistakes in her assumptions.

e. Appeal of Striking of Portions of Company Witness Popa’s Rebuttal Testimony

The following section of this Brief is included to preserve the Company’s ability to appeal the Administrative Law Judge’s ruling striking portions of the Rebuttal Testimony of Company witness Nancy A. Popa in which Ms. Popa provided rebuttal to testimony of Staff witness Rusnak. Specifically the ALJ struck 6 TR 1441 lines 13-24; 6 TR 1442 lines 9-24; and 6 TR 1443 lines 1-3. 6 TR 1433. The ALJ erred when she struck Ms. Popa’s Rebuttal Testimony as it was proper rebuttal which: (i) directly contradicts, repels, explains, and disproves evidence produced by Staff’s witness Ms. Rusnak; and (ii) directly weakens and impeaches Ms. Rusnak’s testimony. The testimony met the legal prerequisites for rebuttal evidence. Established law supports reversal of the ALJ’s ruling striking the testimony.

The ruling by the ALJ should be reversed for the following reasons: (i) Consumers Energy has a statutory right to submit rebuttal evidence and that right should not be lightly taken away; (ii) the stricken rebuttal evidence qualifies as rebuttal evidence, meeting the long-standing legal definition of rebuttal evidence; and (iii) the stricken rebuttal evidence does precisely what rebuttal evidence is supposed to do — it contradicts, repels, explains, disproves, weakens, and impeaches the evidence presented by Ms. Rusnak.

Consumers Energy has a statutory right to submit rebuttal evidence. Section 72(4) of the Michigan Administrative Procedures Act, MCL 24.272(4) states:

“A party may submit rebuttal evidence.”

Similarly, the Commission’s Rules of Practice and Procedure states in Rule 325(3), R460.17325(3):
“*A party shall have the right of cross-examination and shall have the right to submit rebuttal evidence. Surrebuttal evidence may be permitted at the discretion of the presiding officer or commission.*”

(Emphasis added.)

Allowing rebuttal evidence is not discretionary.

The general principles applicable to rebuttal evidence are summarized in *Kirk v Ford Motor Co*, 147 Mich App 337; 338 NW2d 193 (1985); *lv den* 426 Mich 866; 395 NW2d 8 (1986):

“The rule of rebuttal evidence is stated in *People v Utter*, 217 Mich 74, 83; 185 NW 830, 833-834 (1921):

“‘Rebuttal evidence is broadly defined as that given by one party to contradict, repel, explain, or disprove evidence produced by the other party and tending directly to weaken or impeach the same.’” 147 Mich App at 345. (Emphasis added.)

The purpose of rebuttal is to undercut or weaken another party’s case. That is what the stricken testimony of Ms. Popa does.

Consumers Energy cannot anticipate every argument that might be made by another party, or cases would be even more lengthy and complex than they are already. In *Chase v Lee*, 59 Mich 237; 26 NW 483 (1886), the Michigan Supreme Court held exclusion of relevant rebuttal was reversible error. The Court in its opinion stated:

“The testimony was relevant; and where a party offers relevant testimony in rebuttal of the case made by the defendant, it is error to reject it.”

* * *

“...For the errors in rejecting the rebutting testimony, which bore directly upon the subject-matter of the defense, was connected with it, and tended to controvert or disprove it, there must be a new trial.” 59 Mich at 239-240.

In *People v Figgures*, 451 Mich 390, 399; 547 NW2d 673 (1996), the Michigan Supreme Court ruled evidence is admissible during rebuttal when it is responsive to evidence
offered or a theory introduced by a party opposing the rebuttal evidence even if it could have been offered in the case in chief:

“Contrary to the dissent’s insinuation, the test of whether rebuttal evidence was properly admitted is not whether the evidence could have been offered in the prosecutor’s case in chief, but, rather, whether the evidence is properly responsive to evidence introduced or a theory developed by the defendant. As long as evidence is responsive to material presented by the defense, it is properly classified as rebuttal, even if it overlaps evidence admitted in the prosecutor’s case in chief.” 451 Mich 399. (Citations omitted; Emphasis added.)

By Staff’s own acknowledgment in its motion to strike, the Rebuttal Testimony of Ms. Popa that was stricken by the ALJ was directly responsive to the evidence introduced and theories offered by Staff, Staff’s complaint was the evidence is “new evidence regarding environmental regulations not presented through the Company’s direct testimony.” Staff Brief, pg. 2. Staff then referred the ALJ to Case No. U-8871 claiming rebuttal testimony must “not contain evidence which reasonably could have been presented in a party’s direct case.” This interpretation is not correct. The Commission’s holding in Case No. U-8871 actually stands for the proposition that general policy testimony in rebuttal is not appropriate if it does not specifically rebut opposing testimony: “this testimony was merely broad policy testimony and therefore deficient in not specifically indicating what was being rebutted.” October 13, 1988, order in Case No. U-8871. In contrast the Rebuttal Testimony of Ms. Popa that was stricken is focused and directly responds to the testimony, assumptions, methodology, and conclusions Staff has advocated through its witness Ms. Rusnak. Unlike the situation in Case No. U-8871, it is “very clear in that rebuttal testimony what is being rebutted.” Each portion of Ms. Popa’s stricken rebuttal testimony contradicts, repels, explains, or disproves an identified portion or aspect of Ms. Rusnak’s evidence. Each portion tends to directly weaken or impeach the same and provides the basis for said impeachment. This is clearly within the proper scope of rebuttal.
The stricken rebuttal testimony points out Staff made invalid assumptions and incorrectly assumed various environmental regulations were not final. In addition, the stricken rebuttal testimony contradicts Staff’s position the Company did not minimize environmental expenditures to the maximum degree possible, while still maintaining the ability to achieve compliance when the rules do become final and certain. The stricken rebuttal also calls into dispute Staff’s proposed adjustments to capital expenditures and explains how and why these capital expenditures, contrary to Staff’s assertion, are needed and prudent.

Furthermore, Staff’s assertion to the ALJ at page 6 of its motion that the Company “withheld information from Staff until rebuttal testimony” is factually incorrect and without merit. Each of the sections stricken dealt with environmental rules, the finality of each rule and what actions must be taken in anticipation of finality, all in direct contradiction to the testimony of Ms. Rusnak. The status of each environmental rule is public knowledge. In fact, Exhibit A-58 (NAP-6) is a copy of the presentation given to Staff on September 24, 2010, outlining the Company’s environmental strategy.

The Rebuttal Testimony of Ms. Popa stricken by the ALJ is relevant and meets the prerequisites for rebuttal testimony. It should not have been struck. The Commission should reverse the ALJ’s decision and allow for the admission of the stricken portions of the testimony.

3. **Energy Supply Capital Expenditures**

   a. **Company’s Position**

   Company witness David F. Ronk, Jr., Director of Electric Transactions and Resource Planning, testified concerning the capital expenditures for the test year for the Company’s Energy Supply Department. These expenditures are summarized on Exhibit A-36 (DFR-2). According to Mr. Ronk, the Company anticipates capital expenditures in the following
amounts: $571,000 (2010); $627,000 (2011); and $352,000 (9-months ending September 30, 2012). Mr. Ronk describes these capital expenditures and their reasonableness at 3 TR 307-309. No party contested the Energy Supply capital expenditures presented by Mr. Ronk.

4. Business Technology Solutions “BTS” Capital Expenditures

a. Company’s Position

Company witness Leslie E. Roth, Director of Enterprise IT Governance, (and who adopted the testimony of Karen Beers) testified concerning the capital expenditures necessary for the BTS Department. Ms. Roth quantified the projected capital expenditures on Exhibit A-16 (KMB-2). The capital expenditures for this department are $32,252,000 in 2010; $45,009,000 in 2011; and $28,702,000 for the 9-months ending September 30, 2012. 3 TR 562, Exhibit A-16 (KMB-2), line 4. These capital expenditures are for Software Application Projects, Computer Infrastructure and Asset Management, and Major Computing Infrastructure projects. 3 TR 562-571.

Software Application Projects include SAP enhancements and upgrades including implementation of SAP’s Customer Relationship Module 7 (“CMR 7”). CMR 7 improves service to customers, moves to a web based customer service function and supports Automated Metering Infrastructure (“AMI”) enablement. 3 TR 563. Additional Software Application Projects include replacing technologically obsolete systems, updating business systems and data security and improving information support tools. 3 TR 562-563.

Computer Infrastructure and Asset Management includes investments required to provide a secure and reliable computing infrastructure. 3 TR 565. 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. 3 TR 565.
Major Computing Infrastructure projects include updating the Company’s 800 MHz radio communication system, the Land Mobile Radio project (“LMR” project) and the planned construction of a technology center. 3 TR 566, 569. Updating the Company’s communication system is needed as the current system is beyond its useful life expectancy. 3 TR 567. A reliable communication system is necessary to allow contact between dispatchers and crews for both normal work and emergency and storm response. 3 TR 567. A new technology center is needed to provide additional security along with meeting emerging requirements such as space to grow as technology advances while meeting new regulations. 3 TR 569.

It should be noted Staff did not propose any specific disallowances to any of the Company’s proposed capital expenditures for BTS. 5 TR 1072-1080; Exhibit S-2, Schedule B2.

b. Areas of Dispute with the Attorney General

Consumers Energy requests the Commission reject Attorney General witness Coppola’s three recommended disallowances with respect to BTS capital expenditures. Mr. Coppola’s three recommended disallowances are $17.3 million related to CMR 7, $4.1 million related to the LMR project, and $11.6 million related to the construction of a new technology center. 3 TR 579, 582, 583.

Mr. Coppola first recommends implementation of SAP’s CMR 7 not be allowed with a corresponding $17.3 million disallowance. 3 TR 579. Mr. Coppola claims the Company has not adequately justified the need to implement CMR 7. 3 TR 579. As explained by Ms Roth, CMR 7 is a significant project to develop and configure SAP which will both improve service to customers and support the AMI Project. 3 TR 580. Initially, CMR 7 will replace SAP Windows based Customer Service functions with a Web based version. 3 TR 580. CMR 7 will
provide enhanced customer service functions including increased search capabilities for account identification, improved continuity of customer information, and streamlined system navigation. 3 TR 580. Customers will see benefits in having a greater range of questions answered more efficiently and without losing any data previously entered. 3 TR 580-581. CMR 7 will also allow for AMI related remote meter connection and reconnection, the provision of customer interval data, and allow for on-demand customer meter reads. 3 TR 580, 581. As explained by Ms. Roth, CRM 7 is necessary for the Company to continue to provide improved service to its customers and to enable the AMI project. 3 TR 581. The justification for implementation of CMR 7 and its resulting benefits has been explained by Company witness Roth. Mr. Coppola’s proposed disallowance of any funding for CMR 7 should be rejected.

Mr. Coppola’s second recommendation is the entire LMR project be eliminated with a corresponding $4.1 million disallowance based on his conclusion this project is not a priority for the Company. 3 TR 582. As explained by Ms. Roth, the current communications system used by the Company is over 60 years old with electronics almost 20 years old. 3 TR 583. The LMR project will replace aging electronics with current technology. 3 TR 583. Having a fully functional communications system is vital to the Company for both everyday communications as well as for power restoration and emergency efforts. 3 TR 583. The essential nature of a fully functional communications system and its priority to the Company was well documented by Company witness Roth, thus Mr. Coppola’s proposed disallowance of any funding for the LMR project should also be rejected.

Mr. Coppola’s final recommendation is any cost of new technology centers ($11.6 million) be removed from the Company’s capital projections based on his question as to why current locations are not adequate. 3 TR 583. As explained by Ms. Roth, a new data center
would address physical and facility related risks that currently exist within the Company’s present data centers. 3 TR 569-571, 583. The inadequacy of the current data centers to meet future needs of the Company was well documented by Company witness Roth, thus Mr. Coppola’s proposed disallowance of any funding for a new technology center should likewise be rejected.

5. **Smart Grid/Advanced Metering Infrastructure (“SG/AMI”) Capital Expenditures**

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 advanced metering infrastructure. Company witness Maureen Trumble, Smart Grid Program Director, testified concerning the SG/AMI Program. 3 TR 588-609. The Company proposes to begin deployment of SG/AMI technologies in distinct phases, while continuing assessment and validation of business case and benefits at each step of the way. Smart Grid deployment continues to evolve. Two significant differences exist from the deployment plan filed in MPSC Case No. U-16191, which anticipated that meter deployment would commence in 2012 and be concluded by the end of 2014. The Company believes a slower staged deployment (2012-2019) will mitigate risk and allow it to incorporate findings from early deployments into later phases of deployment. 3 TR 596-597. Also, plans for IT systems modification and deployment have been restructured to release new functions over a multi-year period. In addition, during the summer of 2010, the Company determined that given the immature state of the gas metering technology and relatively low benefits associated with gas AMI functions, deployment to the Company’s gas only service territories was not justified at this time. Therefore, the current deployment plan and program business case provides for the installation of gas meter modules to only those gas meters serving customers where Consumers
Energy also provides electric service (approximately 600,000 combination customers). 3 TR 597.

To date, the Company has completed Phase 1, which focused on validating the technology, confirming customer responses to energy usage reduction programs, and testing the assumptions in the Company’s business case. Consumers Energy has begun preparations for meter deployment including implementing software and IT system changes to provide basic system functions required to support the acquisition and installation of smart meters and to accommodate large volumes of data and modified business processes. The AMI system will include electric meters and/or gas meter modules capable of transmitting and receiving data and a two-way communications network. The future modernization of the grid, including the addition of distribution system controls and devices, is expected to be built upon the infrastructure investment that supports the current program. 3 TR 591-592.


The Phase 1 Pilot included the testing and assessment of multiple AMI vendor technologies followed by rigorous field testing to confirm operational performance. This included a pilot that took place in Jackson County, Michigan, where nearly 6,500 smart meters and the communications networks to support them were installed and tested over a two-year period. The primary intent of the Phase 1 Pilot was to confirm network design and vendor performance and develop operational support processes and procedures. Additionally, approximately 750 customers located within the designated pilot area participated in the Dynamic Pricing Program. 3 TR 597. Other primary accomplishments of the Phase 1 Pilot included the creation and support of the Smart Services Learning Center, and development and confirmation of customer interest and participation in SG/AMI enabled pricing and load management programs. Knowledge gained throughout the Phase 1 assessment period was used
to develop a Request for Proposal (RFP) process to select a meter network communications vendor to enable the beginning of a larger scale deployment in 2012 and beyond.

b. **Phase 2 (2011–2013)**

Phase 2 will begin a larger scale deployment to expand operations and systems testing of the selected SG/AMI meter network communication vendor. It will also confirm processes and procedures for support and operations, including best practices from the industry and lessons learned in Phase 1. The Company plans to begin to install electric smart meters in the Muskegon and greater Grand Rapids area. When completed, this phase of deployment will include seven operating headquarters and will allow the Company to monitor and manage the new technology within a finite defined area to ensure the highest level of operational efficiencies and benefits are achieved. Coupled with customer education, communication and programs, Phase 2 will provide a clear method of evaluation and validation of the business case and deployment strategy as the Company continues its measured approach. The current plan for Phase 2 will result in the deployment of approximately 460,000 electric meters and 9,000 gas meter modules during the period of 2012-2014. The deployments will begin in Consumers Energy’s Muskegon work headquarters followed by deployments in Zeeland, North Kent, East Kent, West Kent/Grand Rapids, Allegan, and a small portion of the Kalamazoo area. The current meter deployment schedule by Company work headquarters is graphically presented in Exhibit A-43 (MKT-1). 3 TR 598. If successful, the Company will then continue deployment across Consumers Energy’s electric and combination service territory. 3 TR 595.

The Phase 2 activities are designed to evaluate and test a larger-scale deployment of meters over a varied geographic area and diverse customer base. Knowledge gained from other AMI utility implementations indicates deployment of a significant number of meters is
needed to fully validate that technical design requirements have been met and the business and customer processes and procedures are in place and working effectively in an operating environment. 3 TR 599.

The high-level objectives and expected outcomes from Phase 2 meter deployments are the following: (i) confirm the vendor(s) technology is functioning as planned, field installation practices and procedures are working and optimized, and the supporting back office computer systems are functioning correctly; (ii) ensure the customer education and engagement plans are achieving their desired outcomes; (iii) gain customer and operational experience to ensure network design and field operations are optimized in future phases of deployment; and (iv) validate business case benefits with implementation of new functions that support remote meter reading, customer energy usage web portal, outage management, remote connect/disconnect and recovery of energy loss. 3 TR 599-600.


Phases 3 and 4 consist of two phases of smart meter and associated technology deployments. The Phase 3 deployment (2014–2016) will occur in the area surrounding south and east of the Phase 2 deployment. Final smart meter deployment will occur in the remainder of the Company’s electric and gas combination service territory during 2017–2019. This plan may be adjusted based on Phase 2 results and the lessons learned from other utility deployments across North America. 3 TR 594-595.
d. **IT System Development**

The current plan requires an investment in IT systems and infrastructure to support the following:

- **2012:** Smart Meter acquisition, installation, maintenance, and operating functions, installation of an integrated toolset for SG/AMI program management, Smart meter/AMI based energy billing (monthly) and a portal for customers to view energy usage detail.

- **2013:** Enable remote transactions to improve customer service and bring operational efficiencies, primarily due to a reduction in field trips by operating employees. Examples of operational efficiencies enabled include the elimination of field trips necessary to support customer move in/move out requests and meter rereads. These functions will also enable improved detection of outages and the collection of operating data at the circuit level for the electric distribution system analysis, with the potential for enhanced ability to tailor investments to improve reliability and system performance.

- **2014:** Additional complex billing capabilities to provide more rate options to support variable pricing and potential new offerings like prepay. Anticipated system changes will also support customer in-home devices and the potential for new energy conservation and load management programs. 3 TR 596-597.

e. **Capital Expenditures**

The Company is asking for Commission approval of $53.3 million for capital expenditures for the projected test year. Exhibit A-47 (MKT-5), Summary of Capital Expenditures for the Smart Grid Program, presents the electric and common capital projected expenditures for the Smart Grid Program. The expenditures are categorized into five cost categories: (1) Field Equipment/Facilities; (2) Meters/Modules; (3) Software/Systems Development; (4) Smart Grid Infrastructure; and (5) Pilot Preparation and Project Management. Lines 1, 3, 4, and 5 of Exhibit A-47 (MKT-5) are common to both the electric and gas AMI. As such, these amounts have been prorated to reflect only the electric portion based on the allocation of common infrastructure and other shared expenditures at 14% to gas operations and 86% to electric operations. The Capital Expenditures are described in 3 TR 605-607.
f. **Cost/Benefit Analysis**

Ms. Trumble also presented the SG/AMI cost benefit analysis. The SG/AMI business case analysis continues to be updated as Consumers Energy selects technologies, assesses customer program participation and benefits, and validates costs specific to the technologies selected through the various RFPs issued during 2010. The SG/AMI program business case in the record, which includes both electric and gas costs and benefits, was completed in March, 2011 [Exhibit A-45 (MKT-3)]. The results of this analysis indicate a 20-year positive net present value for the overall program. 3 TR 600.

(i) **Staff’s Position on SG/AMI and a “Cost Recovery Cap”**

Staff sponsored the testimony of Nicholas M. Evans and Patrick L. Hudson to present the Staff’s recommendations regarding SG/AMI expenditures and cost-benefit analysis. Staff recommended $53,259,000 in projected capital expenditures from October 2011 to September 2012 be placed in Plant-In-Service. 5 TR 1048, 1061. Thus, there is no difference in the Company and Staff positions on this item. Staff also supported the Company’s filed position of projected O&M expense for the test year of $7,072,000. 5 TR 1048, 1061. Staff was pleased the Company decided to slow the pace of AMI deployment in comparison to the deployment plan outlined in Case No. U-16191, to address concerns that may arise as the project proceeds. 5 TR 1048-1049. Staff also agreed the project’s cost-benefit analysis produced a positive net present value (“NPV”). 5 TR 1051. Staff further acknowledged it is possible there are benefits that the Company did not include in its cost-benefit analysis due to the fact they are by nature difficult to quantify, such as increased safety to customers due to reduced outage times. 5 TR 1054. Staff recommended full deployment of the Company’s SG/AMI Project in accordance with the policy guidelines adopted in Case No. U-16191. 5 TR 1060.
Staff witness Hudson proposed a “cost recovery cap” whereby the cumulative historical and projected capital investment that qualifies for inclusion in rate base (as Plant-in-Service) is capped at the level of actual and projected benefits. 5 TR 1062-1065. The SG/AMI costs will consist of the project’s lifecycle revenue requirements on a NPV basis. The SG/AMI related benefits will be calculated in terms of the NPV of the actual accumulated benefits and remaining projected lifecycle benefits. 5 TR 1062. Staff intends the Company to be at risk if investment costs exceed projected benefits. Staff suggests that if such a future determination is unfavorable, the Company will not be allowed to recover such costs from ratepayers. 5 TR 1063. So, while Staff supports further deployment of the Company’s SG/AMI Project, Staff recommends the Company remain at risk for such investments for the entirety of meter deployment and duration of the business case through 2032.

The Company respectfully disagrees. Pursuing a project of such scope and magnitude should not be subject to a hindsight review. Company witness Rasmussen was very clear about the inappropriate implications of such a radical policy:

“The Company is in complete agreement with Mr. Hudson that ratepayers should not be harmed if it was determined that the Company made an imprudent investment decision. Once a decision is made and a cost incurred, however, it is not reasonable to later impose a disallowance based on changed circumstances. Such an approach to recovery of AMI/smart grid expenditures would be a different, more onerous standard than has ever been required for any other type of utility investments. Another concern with the Staff’s proposed recovery cap is that investments already approved for inclusion in rates would be at risk for future disallowance if the value of some estimated future benefit does not materialize as expected. Not only is this unfair, the Company believes that this is a ‘hindsight’ approach to ratemaking and is contrary to established legal principles. Further, the mere potential of a future Commission denying recovery of all or some portion of previously approved Smart Grid/AMI investment that had already been placed in commercial operation would force a serious reevaluation of whether to proceed with any investment at all. The
Commission’s traditional prudence review of the Company’s expenditures through the rate case process will continue to ensure an appropriate balance of risk between customers and shareholders.”  3 TR 108.

The Commission should not create such uncertainty on a go-forward basis for the SG/AMI Project.

g.  **Response to the Attorney General’s Position**

The Attorney General presented the testimony of Mr. Coppola who again recommended the Commission not approve any AMI expenditures and should instead order the project be suspended.  4 TR 676, 701.  Mr. Coppola alleges the Company’s Pilot Programs did not gather sufficient information to validate that smart meters will drive change in customer consumption or provide sufficient value to customers.  4 TR 720.  Mr. Coppola also opined the cost/benefit model does not reflect a return on SG/AMI equal to the Company’s cost of capital.  4 TR 722.  Each topic will be reviewed.

(i)  **Attorney General’s Opinion of Phase 1 Pilot Results**

The testimony of Company witness Stephen T. Hirsch, Director of Customer Value Services, provides a summary of, and report on, the Company’s 2010 Direct Load Management Pilot and its 2010 Dynamic Pricing Pilots.  He also provided an overview of how Consumers Energy plans to use the pilot results, information gathered from other forums, and other Company research to ensure that smart grid enabled customer benefits are realized via development of a comprehensive vision for customer education and engagement.  3 TR 376.  During the summer of 2010, Consumers Energy launched a demand response (dispatchable) program piloted in the greater Grand Rapids area to evaluate participants’ response to methods and approaches used to attract and retain customers to this type of program, as well as to determine the load reduction potential from participants during critical peak cycling events.
Approximately 2,200 customers voluntarily enrolled in the program and gave permission to have load control switches installed at their air conditioning units. In addition, during a limited number of peak demand days, the air conditioners were cycled off and on and data was captured to determine actual load reduction impacts. Upon completion of the 2010 program, a telephone survey was conducted among pilot participants and overall satisfaction with the program was high. In addition, a focus group session was held to gauge perceptions of the program and gain insights for improvement of future versions of the program. Customer reaction to the program was very positive, and most participants indicated they would likely participate in the program again. Details on the pilot and program results may be found in Exhibit A-18 (STH-1). The Residential Dynamic Pricing Pilot (marketed to customers as Personal Power Plan), was a type of Non-Dispatchable Demand Response program, where during periods of peak demand, load curtailment is dependent upon what energy consumption/demand customers are willing, and/or able, to curtail in response to either higher energy pricing, or the ability to obtain an incentive. The purpose of the pilot was to test customer response to technology, access to new types of information, and to introduce them to dynamic (time based) rates.

Contrary to Mr. Coppola’s assertions, the pilots were a success. Focus group surveys conducted in the fourth quarter of 2010 demonstrated all customers’ surveyed reaction to both programs was extremely positive, evidenced by the fact a very high percentage of surveyed participants indicated they would like to take part in the pilot programs next summer. One of the Company’s principal objectives in fielding the pilots, to assess customer response to various energy pricing signals, was met beyond expectations. In summary, participants increased air conditioner temperature settings, turned off unnecessary lighting, postponed laundry, and
unplugged appliances not in use. Nothing in the pilots indicated customers would stop participating in Smart Grid enabled programs. In fact the pilots clearly demonstrated customers are very interested in the information that AMI and a Smart Grid provides, and the heightened sense of energy awareness it creates. Feedback from some customers in the post pilot survey indicated they were still taking energy awareness/demand response/conservation measures even though the pilot in which they had participated had concluded. This speaks to the sustainability question regarding longer term behavioral effects and indicates customers will in fact change their “energy lifestyle” in response to enhanced energy information and programs enabled by the Smart Grid. They were very interested in the tools offered, and appreciated the AMI enabled information and education on peak period use as well as the energy saving tips. 3 TR 384-385. Moreover, all of the participants took active steps to reduce their energy usage during critical peak events.

(ii) Attorney General’s Opinion of Cost/Benefit Model

Attorney General witness Coppola criticized the cost/benefit model, claiming the return on this project is below the Company’s cost of capital. 4 TR 722. However, as reflected in the Rebuttal Testimony of Company witness Frederick R. Merry, the methodology that Mr. Coppola used did not properly reflect the use of debt in the after-tax cash flow or the amortization of the debt used to finance the investment. In order to calculate the equity cash flows required to determine equity IRR, Mr. Coppola has rightly considered interest as an expense. However, he did not reduce the initial investment by the debt amount which leads to overstatement of the initial equity investment. Also, Mr. Coppola did not show the future debt principal payments. Although the total debt principal cash flows during the life of the project add up to zero, the timing has a significant impact on the internal rate of return (“IRR”)
calculations. 3 TR 460. After making these critical changes to Mr. Coppola’s Exhibit AG-22, Mr. Merry’s Exhibit A-52 (FRM-1) makes clear that proper amortization of debt results in an IRR on the equity cash flow that is greater than the Company’s return on equity and results in a positive Net Present Value. The SG/AMI project is an economically viable undertaking. 3 TR 461.

Undaunted, the Attorney General filed Surrebuttal Testimony of Mr. Coppola who asserted the actual annual expenditures for SG/AMI should be reduced by the after-tax savings generated by the project and the net cash flows should be discounted by the overall pre-tax cost of capital. 4 TR 770. Mr. Coppola again claimed the project generates a negative NPV. 4 TR 770. But, Mr. Coppola is wrong again. As reflected in the Supplemental Rebuttal Testimony of Mr. Merry, in Mr. Coppola’s revised Exhibit AG-22, Mr. Coppola appropriately corrected his original Exhibit and arrived at a consistent set of cash flows for the IRR calculation. Mr. Merry agrees that Mr. Coppola’s calculation of IRR on the total capital at 8.96% is reasonable. However, Mr. Coppola has incorrectly compared the IRR to the Company’s pre-tax cost of capital instead of after-tax cost of capital. As labeled by Mr. Coppola, Column (h) of his revised Exhibit AG-22 contains “after-tax cash flow” of the project including the after-tax savings/costs from the project. Therefore, the IRR that is calculated using these cash flows (i.e. 8.96%) is clearly on an after-tax basis. Therefore, it needs to be compared with the after-tax cost of capital of the Company, not the pre-tax cost of capital as used by Mr. Coppola. 3 TR 464-465. Using the after-tax cost of permanent capital of 7.33% indicates that the IRR of the project of 8.96% is higher than the cost of capital and therefore is financially viable. In contrast, Mr. Coppola, by using an incorrect comparison, arrived at the wrong conclusion regarding the financial viability of the project. This is extremely unreasonable
and his conclusion should be rejected by the Commission. By using the appropriate cost of capital, NPV also changes to a “positive” $68.9 million, instead of the negative $28.8 million calculated by Mr. Coppola. These revisions are illustrated in Exhibit A-71 (FRM-2). 3 TR 465. Mr. Coppola has incorrectly compared the after-tax IRR of the project to a pre-tax cost of capital and reached an incorrect conclusion on the financial viability of the Smart Grid project. Using the same IRR calculated by Mr. Coppola but comparing it with the right cost of capital proves his conclusion wrong, a conclusion that should be rejected by the Commission.

6. Company Response Regarding Staff’s Plant-In-Service and Plant Held for Future Use Test Year Balances

Consumers Energy used the actual 2010 calendar year balances as its starting point for calculating test year Plant-in-Service, Plant Held for Future Use, and CWIP balances and then added capital additions and plant expenditures and calculated retirements, depreciation, cost of removal and ending balances. 3 TR 171. Staff used updated actual September 30, 2011, Plant-in-Service, Plant Held for Future Use, and CWIP as the beginning balances in calculating test year amounts. 5 TR 1061, 1077-1078. Consumers Energy agrees the September 30, 2011, balances used by Staff for calculating Plant-in-Service, Plant Held for Future Use, and CWIP are correct. 3 TR 188. In an effort to reduce issues in dispute, Consumers Energy is accepting the Staff’s test year averages for Plant-in-Service of $10.175 billion and Plant Held for Future Use of $4.733 billion. See Appendix B, lines 2 and 3. While Consumers Energy agrees with Staff’s use of actual September 30, 2011, CWIP balances as the starting point for calculating the test year CWIP balance (3 TR 188), the Company does not agree with the manner in which Staff calculated test year adjustments to the beginning CWIP balance. Differences regarding test year CWIP are discussed below.
7. **CWIP**

Staff reduced the test year CWIP jurisdictional balance from the $749.89 million amount originally calculated by the Company to $539.61 million. See Appendix B, line 4. While the Company agrees that a slight reduction in the test year CWIP amount originally calculated by the Company is warranted based on use of an updated starting balance, the Company submits that the appropriate revised test year CWIP amount is $696.470 million. See Appendix B, line 4, column (d).

In its determination of test year adjustments to the beginning CWIP balance, Staff: (i) inappropriately excluded environmental compliance capital expenditures (see 5 TR 1165) that record evidence indicates **are required by law** (see e.g., 2 TR 43, 63-64; 3 TR 92, 102; 6 TR 1440); (ii) inappropriately excluded capital expenditures at the Cobb and Whiting Plant needed to safely operate the plants and comply with environmental regulation (6 TR 1342-1344); and (iii) inappropriately excluded capital expenditures for certain projects that, while delayed from earlier in 2011, are projected to occur in the test year (3 TR 106-107).

Staff identified the following capital expenditures as having been excluded:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM 2.5 Environmental Expenditures</td>
<td>$125,615,000</td>
</tr>
<tr>
<td>Mercury Environmental Expenditures</td>
<td>$158,657,000</td>
</tr>
<tr>
<td>316b Environmental Expenditures</td>
<td>$ 1,918,000</td>
</tr>
<tr>
<td>RCRA and Other Environmental</td>
<td>$ 3,910,000</td>
</tr>
<tr>
<td>B.C Cobb Plant Expenditures</td>
<td>$ 5,645,000</td>
</tr>
<tr>
<td>J.R. Whiting Expenditures</td>
<td>$11,161,000</td>
</tr>
<tr>
<td>Reliability Expenditures</td>
<td>$ 9,333,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$316,239,000</strong></td>
</tr>
</tbody>
</table>

For reasons discussed above, Staff’s exclusion of required environmental expenditures in determining the test year CWIP balance is inappropriate and should be rejected. Staff’s exclusion of capital expenditures that are projected to occur during the test year is also inappropriate and should be rejected. As shown on Appendix B, note 3, including these
With respect to delayed expenditures, Consumers Energy’s witness Rasmussen testified:

“The Company does not disagree that the level of actual expenditures through September 2011 are lower than what is reflected in the Company’s request in this filing. However, these differences are an issue of timing, i.e., the Company’s most up-to-date projections indicate that the actual ‘underspend’ of 2011 capital dollars through September 30, 2011 will be made up during the test year in this case. This projected level of increased spending through September 30, 2012 is in addition to the projected level of expenditures identified in the Company’s original filing.” 3 TR 106. (Emphasis added).

Staff witness Kevin Krause testified that Staff assumed that adjustments for reduced expenditures during the first 9-months of 2011 were accounted for by accepting September 30, 2011, plant balances for Plant-in-Service and CWIP. 5 TR 1077. However, this conclusion is not accurate in light of Mr. Rasmussen’s testimony the amount of under-spending during the first 9-months will be offset by increased spending during the test year. 3 TR 106.

Staff identified the total level of Fossil and Hydro capital expenditures it excluded from CWIP as $306.906 million (total electric). 5 TR 1170. In addition, Staff excluded an additional $9.333 million of reliability capital expenditures.4 5 TR 1152. Exclusion of these expenditures is inappropriate, as discussed above in this Brief and in the Company’s Rebuttal Testimony. See 4 TR 879-882. Using the half-year convention, these capital expenditures add $158.120 million5 to Staff’s test year CWIP amount of $542.576 million and would increase the total electric CWIP amount to $700.696 million and the jurisdictional CWIP amount to $696.470 million. Including this revised amount in calculating Rate Base is conservative.

---

4 $76,633,000 less $67,299,750 = $9,333,250. See 5 TR 1152, lines 3-6.
5 ($306,906,000 + $9,333,250 = $316,239,250) / 2 = $158,119,620.
because it does not include capital expenditures that were deferred from prior to the test year into 
the test year. The calculation of the necessary adjustment to the Staff’s test year average for 
CWIP is shown on Appendix B to this Brief.

8. **Clean Coal Plant**

Consumers Energy has included $18.059 million in Rate Base to provide for a 
return on the unamortized balance of Clean Coal Plant expenditures. Support for this adjustment 
is included in the discussion of Clean Coal Plant expenditures contained in Section VI of this 
Brief.

9. **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 September 2011 and 2012. 
3 TR 171. In its initial filing, the Company used the actual 2010 calendar depreciation reserve 
balance as its starting point and then added capital additions and plant expenditures and 
calculated retirements, depreciation, cost of removal and ending balances to determine 
Plant-in-Service, CWIP, and the depreciation reserve. 3 TR 171. As noted above, Staff used 
updated September 30, 2011, actual balances as the beginning balances for the test year. 
5 TR 1078. Using updated actual balances from September 30, 2011, for the beginning balances 
for the test year (5 TR 1078), Staff calculated a jurisdictional depreciation reserve of 
$3.971 billion. Exhibit S-2, Schedule B-1, line 6, column (f). As noted above, Consumers 
Energy has accepted the Staff’s levels for Plant-in-Service and Plant Held for Future Use. 
Consumers Energy is also accepting the Staff’s projected test year accumulated provision for 
depreciation. See Appendix B, line 7.
B. **Working Capital**

1. **Working Capital Methodology and Calculation**

Rate case Working Capital is developed using the balance sheet methodology. Use of the balance sheet methodology was mandated by the Commission in Case No. U-7350. Case No. U-15985 filing requirements also require this method be used to develop rate case Working Capital. The Company is requesting Working Capital be set at $771.980 million for purposes of determining Rate Base in this case.

Company witness Erin A. Rolling, Senior Rate Analyst, testified that the Company, in its initial filing, developed its projected test year Working Capital requirement using the 2010 historical working capital as its starting point. This was first updated to reflect March 2011 actual balances and then the March 2011 balances were adjusted: (i) to reflect changes to accounts receivable financing sponsored by Company witness Dhenuvakonda V. Rao; and (ii) changes in pension and OPEB balances sponsored by Company witness Herbert Kops. Details of the updates are shown on Exhibit A-7 (EAR-47), Schedule B4, pages 1 and 2.

As discussed above, Staff has recommended using updated September 2011 actual balances for the calculation of the Plant-in-Service, Plant Held for Future Use, and CWIP components of Rate Base. Consumers Energy does not oppose this request. However, since updated amounts are used for these Rate Base components, then Working Capital needs to be updated also. Company witness Rasmussen testified:

> “[Up]dating the rate base calculation for only plant in service, plant held for future use, and construction work in progress ignores another key component of rate base – working capital.”
>
> 3 TR 106-107.
Similarly, Company witness Ms. Rolling testified:

“Plant in Service, PHFU, CWIP, and Working Capital are all components of Rate Base. In order to be consistent with the MPSC Staff’s use of September 30, 2011 actual balances, the 13-Month Average Working Capital balance should also be updated. Updating the 13-Month Average Working Capital balance results in an increase in the jurisdictional Working Capital balance of almost $170 million. **If the other balances are updated, then the Working Capital balance needs to also be updated so that it is determined on a more comparable basis.**” 3 TR 188. (Emphasis added).

The total electric net working capital requirement for the projected test year calculated using March 2011 actual amounts as a starting point was $607.919 million with a jurisdictional electric amount of $603.705 million. Exhibit A-7 (EAR-43), Schedule B1, line 9, Exhibit A-7 (EAR-47), Schedule B4. The updated amount is $771.980 million. 3 TR 189. As shown on Appendix B this is an increase of $168.886 million above the Staff’s calculated amount of $603.094 million and an increase of $168.275 million above the Company’s originally calculated amount of $603.705 million.

In the updated calculation, 13-month actual balances were determined at September 30, 2011, then these updated actual balances were adjusted: (i) to reflect changes to accounts receivable financing sponsored by Company witness Rao; and (ii) changes in pension and OPEB balances sponsored by Company witness Kops. 3 TR 189. These adjustments are consistent with the methodology used for the original calculation and with the approach typically used in determining test year Working Capital using the Balance Sheet method. 3 TR 189.

---

6 Staff’s witness Ms. Bankapur testified that Staff removed $600,000 from the Company’s working capital results due to Staff’s removal of the PeopleCare account from accounts receivable in the calculation. 5 TR 1028. The Company disagrees with this adjustment, as discussed below in Subsection 2.
2. **Response Regarding Staff's PeopleCare Adjustment**

Staff witness Kavita Bankapur testified that she removed $600,000 from Working Capital to reflect removal of PeopleCare contributions from accounts receivable based on the reasoning that donations should not be included in Working Capital. 5 TR 1028. Consumers Energy disagrees with this adjustment. Company witness Ms. Rolling explained that in the Company’s calculation of Working Capital, the Company’s contribution to PeopleCare was reflected through a reduction in Accounts Receivable and an increase in uncollectible expense to reflect that this is essentially debt forgiveness. 3 TR 195. Ms. Rolling testified that Staff’s adjustment resulted in inappropriately reducing the Accounts Receivable Balance for a second time, resulting in a double counting of the effects of PeopleCare on the balance sheet. 3 TR 195. The Staff’s adjustment should be rejected. 7

C. **Total Rate Base**

Consumers Energy requests the Commission set rates using a jurisdictional Total Rate Base for the projected test year of $7,653,801,000. The primary components are:

<table>
<thead>
<tr>
<th>Component</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Utility Plant</td>
<td>$10,894,533</td>
</tr>
<tr>
<td>Less: Accum. Depreciation and Amortization</td>
<td>$(3,970,709)</td>
</tr>
<tr>
<td>Net Utility Plant</td>
<td>$6,923,824</td>
</tr>
<tr>
<td>Less: Retainers &amp; Customer Advances</td>
<td>$(42,003)</td>
</tr>
<tr>
<td>Working Capital</td>
<td>771,980</td>
</tr>
<tr>
<td>Total Rate Base</td>
<td>$7,653,801</td>
</tr>
</tbody>
</table>

A more detailed calculation of Rate Base is shown in Appendix B to this Brief.

---

7 Staff witness Welke’s proposed PeopleCare adjustment is discussed in Section V.C.5.b. of this Brief, Uncollectible Expense.
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 6.86%, calculated as set forth on Exhibit A-60 (DVR-12). For the convenience of the Commission, the capital structure and rate of return summary from Exhibit A-60 are reproduced on Appendix E, page 1, to this Brief.

Consumers Energy is requesting that the authorized return on equity be set at 10.70%. This is the same rate of return authorized by the Commission for Consumers Energy in Consumers Energy’s most recent electric rate case, Case No. U-16191. For reasons set forth in the direct testimony and rebuttal testimony of Consumers Energy’s witness Dhenuvakonda V. Rao (see 3 TR 487-518, 526-544) and as discussed below, Consumers Energy requests the ALJ recommend and the Commission find that maintaining Consumers Energy Company’s currently 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 recent Commission orders.

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 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
long-term debt cost rate of 5.70% and Staff’s short-term debt cost rate of 3.52%. Consumers Energy does not agree, however, with Staff’s recommended return on equity of 9.95%. Record evidence supports finding that a return of 9.95% would substantially understate the appropriate return on equity for Consumers Energy’s electric business and would be unreasonable and unlawful.

The difference between the Company’s calculated overall rate of return of 6.86% and the Staff’s calculated overall rate of return of 6.55% is attributable solely to the disagreement concerning the return on equity that should be adopted in this case. Consumers Energy requests the Commission find that it is reasonable to maintain the authorized return on equity at the currently authorized rate of 10.70%, as proposed by the Company, rather than significantly decreasing the return on equity as recommended by Staff.

B. Test Year Capital Structure

In the current case, witnesses for Consumers Energy and the Staff agreed that the rate of return should be calculated using a projected Consumers Energy capital structure for the 12-month period ending September 30, 2012. 3 TR 474-475, Exhibit A-60 (DVR-12), Schedule D1, columns (a) through (d); Exhibit S-4, Schedule D1, columns (a) through (d). Further, as shown on the cited exhibits, Company and Staff witnesses were also in agreement as to the amounts outstanding that should be used in the capital structure. The capital structure, as supported by the Company and Staff witnesses, is reproduced on columns (a) through (d) of Appendix E, p. 1. 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. Rao began with the common equity balance as of December 31, 2010, as shown on Exhibit A-9 (DVR-2), Schedule D1a, page 1, column (e-1) and then made adjustments as shown on column (e-2). 3 TR 475. The common equity adjustment consisted of an adjustment to reflect retained earnings from January 2011 through September 2012 and an adjustment to reflect the average of equity infusions in 2011 through September 2012. 3 TR 475-477. The calculations are shown on Exhibit A-9 (DVR-2), Schedule D1a, page 2. The resulting average common equity balance for the test year is $4.415 million. Exhibit A-9 (DVR-2), Schedule D1, Exhibit A-9 (DVR-2), Schedule D1a, p. 1, Exhibit A-60 (DVR-12). This is the same amount recommended by Staff. Exhibit S-4, Schedule D1.

   b. **Long-Term Debt Balance**

   In determining the test year long-term debt, Mr. Rao began with the December 31, 2010, long-term debt balance and adjusted the balance for projected debt retirements and issuances. 3 TR 477-478. Mr. Rao projected an average long-term debt balance for the test year of $4.134 billion. Exhibit A-9 (DVR-1), Schedule D1, Exhibit A-9 (DVR-2), Schedule D1a, page 1, Exhibit A-60 (DVR-60). The calculation is shown on Exhibit A-9 (DVR-2), Schedule D1a, page 3. This amount is the same as recommended by Staff. Exhibit S-4, Schedule D1.

   c. **Short-Term Debt Balance**

   Mr. Rao projected an average short term debt balance for the test year of $184 million. This balance is shown on line 5 of Exhibit A-9 (DVR-1), Schedule D1, in column (b), in column (f) line 5 of Exhibit A-9 (DVR-2), Schedule D1a, page 1, and on Exhibit A-60.
(DVR-12), line 5, column (b). Mr. Rao stated that the average short-term debt balance is composed of two components: (i) the first is the average short-term debt – revolver balance of $35 million; and (ii) the second is the average short-term debt – Renewable Liability balance of $149 million. 3 TR 478. The short-term debt balance recommended by Staff is the same as recommended by the Company. Exhibit S-4, Schedule D1.

d. **Deferred Federal Income Tax Balance**

Mr. Rao estimated the deferred tax balance based on its proportion of the historical capital structure as of December 31, 2010, which was 15.89%. 3 TR 479. This resulted in a deferred tax balance for the test year of $1.667 billion. 3 TR 479. Mr. Rao stated this method was consistent with the Commission’s order in Case No. U-16191. 3 TR 479. Staff also recommended using $1.667 billion. Exhibit S-4, Schedule D1.

e. **Other Capital Structure Balances**

The Company and Staff used balances for preferred stock and Job Development Investment Tax Credit (“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. 3 TR 479, Exhibit A-9 (DVR-2), Schedule D1a, p. 1; Exhibit S-4, Schedule D1.

2. **The Attorney General’s Proposal to Impute CMS Energy’s Capital Structure Should Be Rejected As It Was When Raised In Case Nos. U-15645 and U-15986**

Attorney General witness Coppola argued in the current case that CMS Energy’s capital structure should be imputed to Consumers Energy with respect to long-term debt, preferred stock, and common equity. Attorney General witness Charles King took a similar position in Consumers Energy’s electric rate case, Case No. U-15645. In its November 2, 2009, order in Case No. U-15645, at pages 16-18, the Commission summarized the positions of the
parties in that case and the ALJ’s recommended conclusion regarding capital structure as follows:

“Consumers and the Staff followed the Commission’s practice of estimating Consumers’ actual capital structure for the test year. . . .

The Attorney General and ABATE recommended a capital structure designed to reflect more closely the capital structure of Consumers’ parent company, CMS Energy Corporation (CMS Energy). . . . The Attorney General and ABATE argued that although Consumers’ rates have been based on a roughly balanced capital structure, CMS Energy, Consumers’ parent company and equity investor, has a capital structure that is much more heavily weighted toward debt. As such, the Attorney General and ABATE argued that the equity return built into Consumers’ rates at the higher common equity percentage overcompensates CMS Energy equity investors who have a smaller actual equity investment.

* * *

The ALJ recommended the rejection of the hypothetical capital structure proposed by the Attorney General and ABATE, noting that the Commission has treated Consumers as a stand-alone company and has established as a reasonable goal that Consumers maintain a capital structure roughly balanced between debt and equity.

* * *

The Commission agrees with the ALJ that the capital structure proposed by the Staff, and agreed to by Consumers, should be adopted.”

On page 10 of its May 17, 2010, order in Case No. U-15986, the Commission again rejected the Attorney General’s argument that a CMS Energy capital structure should be imputed to Consumers Energy, noting:

“The Commission has treated Consumers as a stand-alone company and has established as a reasonable goal that Consumers maintain a capital structure roughly balanced between debt and equity.”
The Commission stated that it was not persuaded that using the capital structure of the parent company is reasonable for Consumers Energy. The same conclusion is appropriate in the current case.

Mr. Rao testified that reasons for rejecting the Attorney General’s capital structure in the current case include: (i) the Attorney General’s capital structure has no relation to the actual or projected capital structure for Consumers Energy; (ii) the Attorney General’s capital structure is developed on a financial basis rather than on a ratemaking basis; (iii) Consumers Energy’s actual capital structure with known and measurable changes is reasonable; (iv) the Commission has traditionally treated Consumers Energy as a stand-alone company for purposes of developing an appropriate capital structure; (v) the Commission has established as a reasonable goal that Consumers Energy maintain a capital structure balanced between debt and equity as a percentage of permanent capital; and (vi) the Commission has rejected similar proposals in the past. 3 TR 545. The Attorney General has presented no valid reason that would justify the Commission reversing course on this issue. The most appropriate capital structure is the projected capital structure of Consumers Energy. 3 TR 545.

C. **Cost Rates**

Consumers Energy and Staff witnesses agreed with respect to cost rates for preferred stock, long-term debt, short-term debt, customer deposits, and other interest bearing accounts.8 As indicated previously, Consumers Energy and the Staff witnesses disagree with respect to cost rates for common equity.

---

8 Consumers Energy and the Staff initially disagreed with respect to cost rates for long-term debt and short-term debt. Consumers Energy through rebuttal adopted the Staff’s rates for long-term debt and short-term debt. 3 TR 527.
1. Return on Common Equity

a. Introduction and Summary of Position – Reducing the Currently Authorized 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 10.70%. This return was last set for Consumers Energy by the Commission in its November 4, 2010, order in Case No. U-16191. In the current electric rate case, Consumers Energy’s witness Mr. Rao presented multiple evidence and arguments supporting maintaining the return on equity at the current rate of 10.70%. Mr. Rao’s recommended 10.70% return is approximately at the midpoint of his range of reasonableness of 10.50% to 11.00%.

The 10.70% return on equity recommended for Consumers Energy is 20 basis points higher than the 10.50% return on equity which the Commission established for Detroit Edison in its October 20, 2011, order in Case No. U-16472. At page 40 of its October 20, 2011, order in Case No. U-16472, the Commission stated:

“[T]he Commission finds that balancing the interests of the ratepayers in just and reasonable rates against the need of Detroit Edison to continue to attract capital from the financial markets justifies setting its ROE at 10.50%.”

The return on equity for Detroit Edison appropriately reflects that Michigan utilities continue to face challenges from the Michigan economy and that returns cannot simply be determined based on mathematical calculations. Consumers Energy has service in 8 of the 10 most impoverished

---

9 At page 28 of its order, the Commission found that an ROE of 10.70% was consistent with the Commission’s desire to ensure, to the extent possible, that Consumers Energy continued to have reasonable access to capital as the economy continued to stabilize and improve.

10 Mr. Rao originally concluded an appropriate return on equity range for Consumers Energy would be 10.70% to 11.00%. In his rebuttal testimony, Mr. Rao revised his recommended range to a range of 10.50% to 11.00% in light of the Commission’s Case No. U-16472 decision and current conditions. 3 TR 528.
Michigan counties. 3 TR 538, Exhibit A-64 (DVR-16). Credit ratings for Detroit Edison and Consumers Energy show investors view investing in Consumers Energy as more risky than investing in Detroit Edison. 3 TR 538, Exhibit A-9 (DVR-11), Schedule D5, p. 10. Mr. Rao presented evidence in rebuttal that, based on differences in credit ratings, Consumers Energy’s return on equity should be 20-30 basis points higher than Detroit Edison’s return on equity. 3 TR 539.

In the current electric case, Staff filed testimony in which it recommended the return on equity for Consumers Energy be set at 9.95%. The Attorney General’s witness proposed a return of 9.70% if the Commission uses Consumers Energy’s projected capital structure. Both of these recommendations significantly understate investor expectations and the appropriate return on equity for Consumers Energy’s electric business. In its orders in Consumers Energy’s Case No. U-16191 and in Detroit Edison’s Case No. U-16472, the Commission concluded the return on equity should be set at a level higher than the Staff’s recommended range. It should do so again in the current case.

Adopting recommendations of the Staff and Attorney General witnesses that the authorized return be reduced from 10.70% to 9.95% 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. This is particularly true given the Commission’s recent establishing of a return on equity of 10.50% for Detroit Edison, a company which has higher (less risky) credit ratings than Consumers Energy.11 The recommendations of the Staff and Attorney General 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

---

11 As credit ratings become lower (i.e., more risky), the investors expect a higher return to compensate them for the increased risk. 3 TR 513.
Considerations with regard to: (i) Michigan risk versus national risk; (ii) Consumers Energy risk versus Detroit Edison risk; (iii) investor return on equity expectations; and (iv) risk aversion and cost of equity. See 3 TR 528-549.

Mr. Rao testified:

“Investors and analysts currently view the Michigan regulatory environment as generally constructive, and an ROE in the range of 10.50% to 11.00% would be commensurate with the risk of investing in the State of Michigan which has a weaker economic climate than other states. Lowering the return on equity for Consumers Energy below 10.50% in this case would send a wrong message to investors and analysts as they consider investment decisions within the State. It would also threaten Consumers’ ability to maintain its existing credit ratings. A reduction below 10.50% would be particularly unreasonable at a time when the U.S. economy is in a fragile situation due to continued high unemployment and large fiscal deficit, capital markets are unstable given the turmoil in Eurozone, financial health of the banks is in question, and the economic recovery in Michigan is at a nascent stage. I believe maintaining the Company’s currently authorized ROE of 10.70% is reasonable given the risk profile for the Company and recent Commission orders but, as I stated above, at a minimum the return should be set no lower than 10.50%.”

3 TR 528.

Mr. Rao provided both qualitative and quantitative support for his conclusion that the cost of common equity should remain at the currently authorized level of 10.70%, rather than be decreased as proposed by Staff and Attorney General witnesses. 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. 3 TR 494. 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. 3 TR 490-491.

c. **Proxy Group Selection Criteria and Investor Risk Perceptions**

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: (i) the company had to be classified as an electric utility company by the Value Line Investment Survey (“Value Line”); (ii) the company had to be paying current common stock dividends; (iii) the company had to 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’s”); (iv) the company had to have approximately 50% or more of its operating revenues from regulated electric operations; (v) the company had to have net plant greater than $5 billion; and (vi) the company had to not be planning to merge with another company. 3 TR 494. The application of these screening criteria resulted in a group of 21 companies. 3 TR 494.

Mr. Rao testified this proxy group was representative of the electric industry as a whole and could be used in evaluating an appropriate return for Consumers Energy’s electric business. 3 TR 494. However, he concluded that the proxy group, taken as a whole, had less risk than Consumers Energy. 3 TR 511-512. Factors that support a conclusion that investors view Consumers Energy as having greater risk than the proxy group include: (i) credit ratings; (ii) earned returns; (iii) ability to consistently earn authorized returns; and (iv) that Consumers Energy is operating in the struggling Michigan economy. 3 TR 511-517, Exhibit A-9 (DVR-8), Schedule D5a, pp. 1-2, Exhibit A-63 (DVR-15), Exhibit A-64 (DVR-16).

Mr. Rao testified the Michigan economy is of particular concern to investors:

“Operating in the struggling Michigan economy is a major factor that differentiates Consumers from the rest of the proxy group. . . . Investors are concerned that, over the near term, Michigan will lag the nation’s economic recovery, will lag the nation’s economic performance, and that economic recovery for Michigan will be slower. These factors increase investor perceived risks and uncertainties of investing in Michigan and result in additional
investor-perceived business risk relative to the proxy group.”
3 TR 515-516.

It would be unreasonable and unlawful to ignore the impacts of the Michigan economy and other risk differences in determining an authorized return on equity for Consumers Energy.

Mr. Rao testified the difference in risk between the proxy group and Consumers Energy must be taken into account in evaluating proxy group results:

“The screening criteria are a necessary step in identifying companies that can be used in evaluating an appropriate return for Consumers Energy’s electric business. However, it is necessary, in addition, to evaluate how the risk of the proxy group, taken as a whole, compares to the risk of Consumers Energy. It is a fundamental principle that equity investors in a regulated utility are entitled to a return commensurate with investments of comparable risk. Consequently, the relative risk of the proxy group compared with Consumers Energy must be considered.” 3 TR 511-512

Mr. Rao testified that, as a result of the proxy group having lower overall investor-perceived risk, the proxy group analyses would produce return on equity results that are lower than a return on equity that is appropriate for Consumers Energy’s electric business. 3 TR 516. He stated that adjustments to increase the proxy group results need to be made to recognize this risk differential. 3 TR 516. These adjustments are discussed below.

d. Analytical Methodologies and Conclusions

Mr. Rao assessed the return on equity for Consumers Energy’s electric operations using multiple methodologies in combination assessments of the market and risk environment for Consumers Energy. Among other things, Mr. Rao: (i) studied the current outlook of the national and Michigan economies and capital markets; (ii) analyzed the investor perceptions of the Michigan regulatory environment and risk factors associated with investment in Consumers Energy; (iii) 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; (iv) compared investor perceptions of Consumers Energy’s risk with investor perceptions of Detroit Edison’s risk; and (v) compared his ROE recommendation with the returns authorized by the Commission in Consumers Energy’s and Detroit Edison’s most recent electric rate cases. 3 TR 487-489, 529-533.

As part of his assessment, Mr. Rao undertook analyses using the Capital Asset Pricing Model (“CAPM”), a Risk Premium analysis, the Discounted Cash Flow (“DCF”) model, and the Value Line Book Value ROE method. In addition Mr. Rao undertook a comparison to Consumers Energy’s authorized electric return on equity and to Detroit Edison’s authorized return on equity. These analyses are described at 3 TR 495-506, 517, 537-539.

Since it is fundamental that “the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks” (see discussion of applicable principles, supra), it was necessary, as noted above, to adjust the results to recognize this risk differential. Mr. Rao testified that equity involves more risk than investment in bonds, and consequently the cost of the equity differential between the proxy group and Consumers Energy would be higher than the cost of debt differential. 3 TR 513. Mr. Rao estimated a difference in bond spreads between the proxy group and Consumers Energy of 15 basis points. 3 TR 513-514. Using CAPM analysis and the concept of levered and unlevered betas, Mr. Rao calculated an equity risk differential between the proxy group and Consumers Energy of approximately 30 basis points. 3 TR 513-514, 516-517. This is illustrated on Exhibit A-9 (DVR-8), Schedule D5a, p. 2.

The diagram below provides an illustration of Mr. Rao’s conclusions regarding the relative risk between debt and equity for the proxy group as compared to Consumers Energy:
3 TR 517. Mr. Rao stated that this adjustment of 30 basis points could also be viewed as an adjustment for Michigan-specific risks that are not present in the proxy group. 3 TR 516.

The proxy group risk-adjusted returns shown on Exhibit A-9 (DVR-11), Schedule D5, pp. 10, 13, as updated at 3 TR 528, 539 are as follows:

<table>
<thead>
<tr>
<th>Proxy Group/Utility Results with Risk Adjustment</th>
<th>Average</th>
<th>Median (If Applicable)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Asset Pricing Model Application Historical Risk Premium (Line 1 + Line 6)</td>
<td>10.06%</td>
<td>9.95%</td>
</tr>
<tr>
<td>Risk Premium Analysis Over Utility Bonds (A-/A3 Rated Utilities) (Line 2 + Line 6)</td>
<td>10.57%</td>
<td></td>
</tr>
<tr>
<td>Discounted Cash Flow Model Application (Line 3 + Line 6)</td>
<td>10.54%</td>
<td>10.42%</td>
</tr>
<tr>
<td>Value Line Book Value ROE (Line 4 + Line 6)</td>
<td>11.80%</td>
<td>10.72%</td>
</tr>
<tr>
<td>Comparison to Detroit Edison Authorized ROE (as revised in Rebuttal)</td>
<td>10.70-10.80%</td>
<td></td>
</tr>
<tr>
<td>Recommended Cost of Equity Range for Consumers Energy (as revised in Rebuttal)</td>
<td>10.50% - 11.00%</td>
<td></td>
</tr>
<tr>
<td>Recommended Ratemaking Cost of Equity for Consumers Energy:</td>
<td>10.70%</td>
<td></td>
</tr>
</tbody>
</table>

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. 3 TR 491-492. Mr. Rao explained:

“The models are based on the assumption that economic conditions are relatively stable. That assumption is not currently being met. Markets are volatile and there is significant uncertainty. As a result, the models tend to understate the return that investors currently require to compensate them for risk.” 3 TR 491.
The adjustment for the risk differences between the proxy group and Consumers Energy discussed above would not address this issue.

In addition to the above analyses and comparisons, Mr. Rao compared his recommended 10.70% ROE to returns recently authorized by regulatory authorities in other states. 3 TR 508. Exhibit A-9 (DVR-11), Schedule D5, page 12, provides a history of returns on equity authorized for electric companies in orders issued during the last 10 years and compares the returns with 10-year Treasury rates during the same time period. Mr. Rao indicated the average return authorized in 2010 was 10.35%. 3 TR 508. He testified that the ROE versus 10-year Treasury rate comparison supports a conclusion that a return of 10.70% for Consumers Energy is reasonable considering the fact investing in Michigan is viewed as riskier than investing in other states and a projected rise in Treasury rates. 3 TR 508.

Mr. Rao testified:

“What return on equity is appropriate depends upon multiple considerations and must be determined using professional judgment having regard for all relevant facts. The authorized ROE is an important signal that the Commission sends to the investment community. One of the well-established principles for determining a regulated utility’s return on equity specifies that the return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate under efficient and economic management to maintain and support a utility’s credit and enable it to raise money necessary for the proper discharge of its public duties. The currently authorized return of 10.70% meets these criteria.” 3 TR 506-507.

Consumers Energy submits that the evidence, on the whole record, supports a conclusion that maintaining the currently authorized return on equity of 10.70% will reasonably balance customer and investor interests.
e. **Additional Risk Considerations**

Mr. Rao testified the cost of capital is an opportunity cost. 3 TR 529. He stated that in order to induce investors to purchase common stock or bonds there must be a prospect of receiving earnings that are sufficient to make the investment attractive compared with other investment opportunities. 3 TR 529. The Staff and Attorney General return on equity recommendations would not make equity investments in Consumers Energy attractive compared with other business opportunities. 3 TR 529-544, 546-549. Reasons that those recommendations would not make investments in Consumers Energy attractive compared with other business opportunities include those summarized in this section.

(i) **Michigan Risk Versus National Risk**

Mr. Rao testified investors perceive that investments in Michigan have a higher risk than the national average risk and require what he referred to as a “Michigan Risk Premium” in order to invest capital in Michigan. 3 TR 533. Mr. Rao stated Michigan’s economy has gone through unprecedented challenges and has continued to lag the rest of the country. 3 TR 533. He stated that although the Michigan’s economy has started to show signs of recovery, investing in Michigan is still seen by investors as riskier compared to other states. 3 TR 488, 494.

Exhibit A-63 provides a summary comparison of Michigan and the United States on key economic indicators during 2000-2010. 3 TR 534. Mr. Rao stated that over the near term, investors expect Michigan recovery to lag the nation’s economic performance, with economic recovery for Michigan coming later and slower than in some surrounding states. 3 TR 534. He testified:

“Michigan-specific considerations are particularly important to investors in the current economic and investment environment. The return must be adequate to compensate for risks and
uncertainties that are unique to Michigan in addition to other risks.” 3 TR 503.

Mr. Rao stated investors are looking for confirmation that the Commission understands the investment community and the importance of returns in attracting capital to Michigan and they are looking for indications that the Commission desires to keep Michigan utilities healthy. 3 TR 507.

Michigan-specific investor perceived risks affecting Consumers Energy are similar to those affecting Detroit Edison. 3 TR 505. The investor-required Michigan risk premium is reflected in the equity returns authorized for Consumers Energy in Case No. U-16191 and for Detroit Edison in Case No. U-16472. The 10.70% return authorized for Consumers Energy in Case No. U-16191 is 40 basis points above the national average authorized returns shown on Exhibit S-4, Schedule D-5, page 10 as the average awarded ROE for the fourth quarter 2010 and 42 basis points above the 2010 average shown. 3 TR 536. The 10.50% return authorized for Detroit Edison in October 2011 is 26 basis points above the second quarter national average shown on the exhibit and 20 basis points above the average ROE shown for the first half of 2011. 3 TR 536. The recommendations of the Staff and Attorney General in the current case to reduce the authorized return below recently awarded returns are inconsistent with well-established principles for determining utility authorized returns on equity and fails to reflect the investor-perceived risk of investing in a Michigan utility.

(ii) Consumers Energy Risk Versus Detroit Edison Risk

As noted above, the United States Supreme Court in Bluefield, supra, stated a public utility is entitled to earn a return generally being made at the same time and in the same part of the country on investments which have corresponding risks and uncertainties. 262 US 692. Mr. Rao testified that in determining an authorized return on equity for Consumers
Energy in this case, it is particularly appropriate to consider the return authorized for Detroit Edison’s electric business since Detroit Edison: (i) is a Michigan electric utility; (ii) operates in the same part of the country; (iii) investors view it as having less risk, as reflected by its senior secured credit ratings; and (iv) the Commission has recently reviewed Detroit Edison’s return on equity and determined that it should have an authorized ROE of 10.50%. 3 TR 537. Mr. Rao testified that investors view Detroit Edison as an alternative investment and it provides a significant proxy company. 3 TR 537.

Consumers Energy must compete for investment dollars with other utilities in Michigan as well as with utilities in other states. 3 TR 503. Detroit Edison’s senior secured debt is rated two notches higher than that of Consumers Energy by Standard and Poors (A versus BBB+), one notch higher by Moody’s (A2 versus A3), and one notch higher by Fitch (A- versus BBB+). 3 TR 504, Exhibit A-62 (DVR-14). Mr. Rao testified these ratings reflect assessments by the three rating agencies that Consumers Energy has greater risks and uncertainties than Detroit Edison from an investor standpoint. 3 TR 504. As noted earlier, Mr. Rao testified that based on differences in credit ratings, Consumers Energy’s return on equity should be set 20 to 30 basis points higher than Detroit Edison’s. 3 TR 539, Exhibit A-9 (DVR-11), Schedule D5, p. 10.

Mr. Rao emphasized investors expect a utility with more investor-perceived risk to have a higher return on equity. 3 TR 538. The return on equity recommendations of the Staff and Attorney General asking that the return for Consumers Energy be set at a lower rate than the recently established return for Detroit Edison should be rejected. If Consumers Energy’s return on equity were to be set at less than 10.50% then an alternative investment in Detroit Edison, with its authorized return of 10.50%, would result in higher expected return with less risk.
Mr. Rao testified that this result would be inconsistent with fundamental principles of risk-return parity. 3 TR 539. The return on equity authorized for Consumers Energy should be higher than the return on equity authorized for Detroit Edison rather than lower.

(iii) **Investor ROE Expectations**

Mr. Rao testified the authorized return on equity is an important signal the Commission sends to the investment community. 3 TR 539. He indicated investors view the recent Detroit Edison return on equity as a peer benchmark. 3 TR 541. Mr. Rao stated that setting the rate of return at 9.95% as recommended by Staff 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. 3 TR 539. An authorized return of 9.95% would not be reasonable. 3 TR 541.

Consumers Energy presented evidence that, over the next five years, the Company plans to invest more than $6 billion in Michigan to maintain and improve utility infrastructure, increase the amount of energy generated from renewable resources, and ensure that Company customers receive the quality of service that they expect. 3 TR 92, 529-530. Mr. Rao testified that maintaining a relatively stable return on equity is important in keeping Consumers Energy healthy and in attracting capital to Michigan. 3 TR 508-509. Reducing the return on equity as proposed by the Staff and the Attorney General could lead to increases in cost of capital or limit access to capital. Neither would be in the best interest of customers. 3 TR 539.

(iv) **Risk Aversion and Cost of Equity**

Mr. Rao testified that when economic prospects are uncertain, as they are currently, stock markets tend to be volatile. 3 TR 543. He stated that during times of high
volatility the cost of equity capital tends to be higher, in contrast to bond markets which are
governed by Treasury yields and bond rating spreads. 3 TR 543. He explained that during such
times:

“A decrease in interest rates does not necessarily correspond to a
decrease in cost of equity. In fact, a decrease in interest rates that
results from ‘flight to safe haven’ phenomenon is not a good sign
for equity markets as the stock prices will be depressed and the
cost of equity becomes high due to risk averse nature of the
investors.” 3 TR 543.

Mr. Rao testified:

“I believe that the market currently and during 2012 will remain in
a period of risk aversion. As I mentioned earlier in this section of
my testimony, the economy is and will be, for some time, in a
fragile and volatile condition. I believe that this phenomenon
should be factored into ROE decisions in this case. As noted
above, low or declining interest rates do not necessarily equate to
low or declining cost of equity and they can actually have an
inverse relationship. This is the situation currently with respect to
Consumers Energy’s return on equity.” 3 TR 544.

He stated economic recovery has been anemic, that there remain fundamental concerns, that the
U.S. economy is very fragile, that the road to recovery will be long and uncertain given global
issues and weak U.S. fundamentals, and “these factors increase investor risk perceptions and
make investors more cautious in investing in companies viewed as having greater risk due to
location, regulatory environment, or otherwise.” 3 TR 542. Reducing the authorized return on
equity as proposed by the Staff and the Attorney General would be inconsistent with these
considerations.

f. Additional Response to Attorney General

The Attorney General’s witness Mr. Coppola was critical of Mr. Rao’s use of a
direct comparison to Detroit Edison’s authorized return on equity as support for Mr. Rao’s return
on equity recommendation for Consumers Energy. For reasons discussed above, a direct
comparison is reasonable and appropriate. Analyzing how the recommendation in the current case compares to a recent Commission order issued in October 2011 for the other major electric utility in Michigan is a relevant consideration.

Mr. Rao stated that one reason a comparison is important is that it is important to investors. 3 TR 547. Mr. Rao testified:

“Investors consider Detroit Edison as a direct benchmark to Consumers Energy and a comparable investment alternative. The similarities between Consumers Energy and Detroit Edison include:

- Both Consumers Energy and Detroit Edison operate large Electric utilities.

- Both Consumers Energy and Detroit Edison operate in the State of Michigan.

- Both Consumers Energy and Detroit Edison operate under the same regulatory and legislative framework and are both under the jurisdiction of the Michigan Public Service Commission.

- Both Consumers Energy and Detroit Edison share risks surrounding high unemployment, poverty, and a struggling economy in their service territories (as detailed further above [3 TR 538], under rebuttal to Staff).” 3 TR 547

As discussed above, independent credit rating agencies view Consumers Energy as more risky than Detroit Edison. The Attorney General’s recommendations would not provide Consumers Energy with an adequate return commensurate with the risks it faces.

g. Return on Equity Conclusion and Request for Relief

For reasons addressed above and in the evidentiary presentation of Consumers Energy’s witness Mr. Rao, Consumers Energy requests the authorized return on equity be maintained at the current authorized level of 10.70% rather than decreased as proposed by the Staff and the Attorney General. If the return is decreased, then it should at least be equal to the
authorized level of 10.50% established for Detroit Edison and, in any event, should not be reduced below 10.50%. A reduction below 10.50% would be particularly unreasonable given current economic and financial conditions, the slow recovery in Michigan, 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 and the Staff results in an overall after-tax rate of return of 6.86% as compared to the 6.55% overall rate of return calculated by Staff using a 9.95% return. The calculation of the 6.86% overall rate of return is shown on Appendix E, page 1.\textsuperscript{12}

2. **Long-Term Debt Cost**

Staff and the Company witnesses have used a 5.70% cost rate for long-term debt in this case. Exhibit A-60 (DVR-12), Exhibit S-4, Schedule D-1, p. 1, 3 TR 527. The calculation of this cost rate is shown on Exhibit S-4, Schedule D-2, p. 1.

3. **Short-Term Debt Cost**

The updated cost rate for short-term debt that the Staff calculated, and the Company accepts is 3.52%. Exhibit A-60 (DVR-12), Exhibit S-4, Schedule D-3, p. 1, 3 TR 527.

4. **Other Cost Rates**

The Company and Staff are in agreement that the cost rate for preferred stock should be 4.46% (see Exhibit A-9, Schedule D4), 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-60, Exhibit S-4, Schedule D1, p. 1.

\textsuperscript{12} If the lower end of Mr. Rao’s range were used and the return on equity were set at 10.50%, the same as the authorized return on equity for Detroit Edison, this would result in an overall after-tax rate of return of 6.78%. The calculation of the overall rate of return using the capital structure and cost rates for other components as proposed by Consumers Energy and the Staff is shown on Appendix E, page 2.
D. **Overall Rate of Return**

Using a return on equity of 10.70% in the capital structure (recommended by Company and Staff witnesses) in combination with the cost rates for the other components (recommended by Company and Staff witnesses) results in an after-tax cost of capital of 6.86% and a pre-tax weighted cost of capital of 9.76%. The capital structure, cost rates, and calculation of these returns are shown on Exhibit A-60 (DVR-12), and reproduced in Appendix E, page 1. Consumers Energy requests the Commission adopt the capital structure and cost rates as shown on Appendix E, page 1, to this Brief.

V. **ADJUSTED NET OPERATING INCOME**

A. **Jurisdictional Revenues and Sales Forecast**

In this case, the projected test year includes the time period of October 2011 to September 2012. Company witness Lincoln D. Warriner presented the Company’s analysis of historical and projected test year electric operating revenue under current tariff rates for use in this rate proceeding. He made adjustments to 2010 historical actual sales and revenues for the purpose of developing the projected October 2011 to September 2012 test year sales and revenues. 4 TR 920-926. He presented the Company’s official forecasts of electric deliveries, generation requirements, and peak demand for the years “2011–2015.” 4 TR 927-935; Exhibit A-10 (LDW-3), Schedule E-3.

As indicated in Exhibit A-10 (LDW-1), Schedule E-1, the forecast for Total Electric Operating Revenue for October 2011 to September 2012 is $3,738.772 million. This amount was adjusted to $3,747.275 million 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 $3,725.535 million.
Staff witness Mark J. Pung testified that Staff accepted and did not have any adjustments to the present revenue presented by the Company. 5 TR 1122-1123.

Mr. Warriner projected Total Company electric deliveries to increase about 788.8 GWH from 2010 to the projected test year period. 4 TR 926. Weather increased usage in 2010 about 661.1 GWH above normal weather conditions. The Company has experienced significant changes in its industrial customer base. Production capacity of semiconductor and solar energy components within the Company’s service territory is increasing, and electric service under the Company’s economic development rate E-1 is expected to be 838.0 GWH higher during the test year than in 2010. In addition, improving economic conditions will result in usage growth of 611.9 GWH, after accounting for savings from the Company’s Energy Optimization Plan. 4 TR 926-927.

In addition to changes in customer usage from 2010, the Company’s revenue outlook is influenced by the rates approved by the Commission in its order in MPSC Case No. U-16191. 4 TR 927.

1. **Response to the Attorney General**

Attorney General witness Coppola adopted the same electric deliveries projected by the Company for all customer classes other than Residential. 4 TR 680. He recommended the Commission reduce the Company’s requested revenue deficiency by $39,054,000 by increasing the level of test year residential sales by 434,133 MWh as shown on Exhibit AG-4. 4 TR 681. Mr. Coppola compared the August 2011 residential year-to-date sales to the August 2010 year-to-date residential sales and concluded the year-over-year growth rate was 0.9%. He then divided the year-over-year growth rate by the number of months between January and August to determine the monthly rate, and extended that growth rate forward to the projected test
year, concluding that the test year period residential sales should exceed 2010 weather normalized residential sales by 2.4%. 4 TR 938. He applied an “average rate” to calculate additional residential sales revenues.

Mr. Coppola’s assumption that residential sales will continue to grow at the same rate as the first 8-months of 2011 is not well founded. Actual residential sales have changed at a much slower rate than Mr. Coppola anticipated in his projection. Through October 2011, year-to-date actual residential class sales only grew 0.1% over the same time period in 2010, and weather normalized sales actually declined -0.2%. 4 TR 938-939. In summary, Mr. Coppola’s recommended residential sales adjustment of 434,133 MWh is incorrect because he assumed that year-over-year growth through August 2011 was a reliable basis for forecasting sales growth into the future. Actual residential sales through October indicate his assumption was incorrect.

Mr. Coppola’s calculation of his proposed decrease in revenue deficiency applied an average rate of $0.08996 (see Exhibit AG-4). However, this average rate is too high to use in his estimated decrease in revenue deficiency for two reasons. First, Mr. Coppola identifies this as a proposed average rate. Using proposed rates that have not yet been approved overstates the revenue deficiency impact of Mr. Coppola’s proposed change in sales. 4 TR 939. Second, the use of an average revenue rate will always overstate the change in revenue deficiency because average revenue rates include recovery of fuel and purchased power supply costs. Mr. Coppola did not make any estimate of additional costs that would be incurred by the Company to serve the additional sales he proposed, and he did not do any analysis to balance jurisdictional PSCR revenues with jurisdictional PSCR costs. 4 TR 939-940.

The Commission should reject Mr. Coppola’s recommended change to the Company’s residential sales forecast and the corresponding change in revenue deficiency.
2. **Response to NRDC/MEC**

NRDC/MEC presented the testimony of Ms. Richards that the Company’s load forecast “appears to be aggressive.” 6 TR 1461. The NRDC/MEC witness opines that no economic growth should be forecasted to ensure that Consumers Energy is not going to over-invest in power supply resources. 6 TR 1463. The Company respectfully disagrees that its forecasts should be modified to support NRDC/MEC’s agendas.

The Company’s load forecasts are vital to projecting future sales. An intentionally reduced load forecast necessarily results in the expectation of lower sales levels in that time frame. As fixed costs are spread over sales forecasts, higher rates must be allocated to satisfy the fixed cost recovery. NRDC/MEC’s hypothesis that “CEC may collect revenues from ratepayers disproportionate to its need” (6 TR 1462) is backwards. Over-collection is inevitable if load forecasts are manipulated to project sales lower than expected.

**B. Fuel, Purchase and Interchange Expense**

Company witness Ronk testified concerning the Company’s projected fuel, purchased and interchange power expense. See, generally, 3 TR 309 et seq.; Exhibit A-37 (DFR-3). Mr. Ronk explained that these power expenses were projected using production cost simulations. 3 TR 309. Specifically, the PROMOD IV program developed by Ventyx was used to prepare these simulations. 3 TR 310. This program “simulates the operation of the Company’s generating system and purchased power sources to meet projected customer demand.” Id. This model also includes the availability of interchange power. Id. Mr. Ronk testified that the total projected energy supply expense for the 12-months ending September 30, 2012, is $1,681,236,000. Exhibit A-37 (DFR-3), page 1 of 3, line 26. This amount, together with the credit set forth on Exhibit A-37 (DFR-3), page 3 of 3 ($40,934,000) as well as the test
period transmission expense of $285,024,826, 3 TR 309-311, Exhibit A-38 (DFR-4), line 1, constitutes the total fuel, purchased and interchange power expense for the test year of $2,007,195,000. That amount has been jurisdictionalized to reflect the amount to be included in the calculation of the Company’s rates for the test period. See, Exhibit: A-8 (EAR-48), line 5.

No other party contested this amount and the MPSC 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 2 (jurisdictionalized).

C. Other O&M Expense

1. Electric Distribution O&M Expense

   a. Company’s Position


   Mr. Anderson testified that the 2010 Electric Distribution O&M expense was $219,101,000, and the 2011 Electric Distribution O&M expense was $233,193,000. 4 TR 847-850. Mr. Anderson calculated the projected Test Year O&M expense to be $246,497,000 for the Electric Distribution Department. 4 TR 847-848. The projected Test Year O&M expense is comprised of: (i) electric division expense of $166,961,000; (ii) forestry expense of $53,000,000; and (iii) LIEEF expense of $26,536,000. Exhibit A-12 (JRA-1). The Test Year electric division expense is derived though the Company’s strategic planning process
and reflects adjustments made predominantly for expanded distribution pole inspection, expanded pole top maintenance, and the expanded NERC PRC-005-2 standard. 4 TR 849-850. The electric division expenses are reasonable and appropriate with the Company ranking near the top (lower cost) of the second quartile on a least O&M cost-per-customer basis when compared to other utilities. 4 TR 850.

The LIEEF program has been terminated. In legislation passed in December 2011, however, the legislature created a Vulnerable Household Warmth Fund (“VHWF”), and authorized funding by continuing the previously approved LIEEF amounts for certain utilities, including Consumers Energy, at the same level. See MCL 460.9q(19-22).

The forestry expense and the basis for the requested $53,000,000 is detailed in Mr. Anderson’s testimony at 4 TR 855-861. The overall goal of the Company’s proposed forestry expense is increased customer satisfaction and benefit through improved reliability while minimizing the long term unit cost per mile for line clearing. 4 TR 860. As shown in Exhibit A-12 (JRA-1), line 2, column (d), the total projected test year expense the Company is requesting be included in rates for line clearing is $53,000,000 which supports clearing approximately 7,900 miles. 4 TR 855. This compares to 4,924 miles at the expense of $34,188,000 in 2010 shown in column (b), and a plan of 7,100 miles at the planned expense of $48,600,000 in 2011 shown in column (c). 4 TR 855-856. This requested funding will result in line clearing of approximately 25% of the high voltage distribution (“HVD”) system, and approximately 12.5% of the low voltage distribution (“LVD”) system annually (or an effective clearing cycle of approximately eight years). 4 TR 856.

The Company’s distribution system consists of approximately 54,000 miles of overhead primary LVD lines and approximately 4,500 miles of overhead HVD lines. 4 TR 856.
Trees are the number one cause of outages on the Company’s electric distribution system, causing approximately 22% of customer interruptions over the five year period of 2006-2010. 4 TR 856. While an improving trend has been realized in tree-caused outages over the past few years, the longer term trend is still slightly increasing. 4 TR 856. Decision Analysis Modeling indicates the most cost effective way to improve system conditions and reliability is by reducing tree-caused interruptions through an increased level of line clearing. 4 TR 857.

The proposed funding level in this case of $53,000,000 represents the next step of a longer term plan to achieve a level of forestry spending which optimizes the overall benefit to customers through improved reliability performance while maintaining a reasonable unit cost per mile trimmed. 4 TR 857. Ideally, the Company needs to achieve an optimal forestry program of approximately 14% clearing per year for the LVD system (or an effective clearing cycle of approximately seven years) and a 25% clearing per year for the HVD system which would cost approximately $59,000,000. 4 TR 856-857. As explained by Mr. Anderson, the 14% clearing program (approximately 7-year effective cycle) for the LVD system represents the optimal clearing interval for the different system voltages and respective system miles for those voltages. 4 TR 857. In general, the risk of tree-caused outages on LVD circuits increases significantly as the time since last cleared increases, particularly during storms. 4 TR 857. LVD circuits operating at 14.4 kV begin to show dramatic increases in tree related outages after three years since last cleared with 7.2 kV and 4.8 kV circuits showing increases after seven and eight years, respectively, since last cleared. 4 TR 857.

The Company’s actual annual average LVD miles cleared over the last 10 years (2001–2010) has been approximately 3,700 miles which is about 7% of the system annually or about a 14-year effective clearing cycle. 4 TR 858-859. This overall clearing rate has allowed
vegetation conditions to continually grow at a rate faster than miles cleared annually, resulting in approximately 40% of the LVD system that has not been cleared in 10 or more years. 4 TR 858-859. This level of clearing is in contrast to the average 4-year effective clearing cycle utilized by domestic electric utilities as established by benchmarking studies. 4 TR 858-859. Shorter clearing cycles result in less outage impact due to vegetation, lower line clearing cost per mile, and less dramatic impact on customers’ property when line clearing does occur. 4 TR 859.

The overall goal of the Company’s proposed forestry expense is increased customer satisfaction and benefit through improved reliability while minimizing the long term unit cost per mile for line clearing. 4 TR 860.

b. **Areas of Dispute with Staff**

Consumers Energy requests the Commission reject Staff witness Reasoner’s proposed forestry spending level of $41,237,273.13 Mr. Reasoner suggests annual forestry expenses should be based on what was approved in the Company’s last rate case (Case No. U-16191) adjusted by an inflation rate of 1.73%. 4 TR 875. Mr. Reasoner also suggests the Company’s request for $53,000,000 in forestry O&M expense cannot be justified until the Company can demonstrate the previously approved amount has or will result in improved distribution reliability. 4 TR 875. What this argument fails to recognize is that the historical average level of forestry spending did not adequately address the overall system tree conditions by which normal tree growth caused reliability deterioration at a rate faster than what had been addressed with the historic spending levels. 4 TR 875.

The inadequacy of the historic level of spending relative to vegetation growth is extensively detailed by Mr. Anderson at 4 TR 858-859. The benefit of full circuit line clearing

---

13 There is a slight discrepancy with Staff witness Welke’s Exhibit S-3, Schedule C5, line 2, which shows a Staff recommendation of $41,083,000 for forestry.
relative to circuit reliability is shown on pages 44 and 45 of the “DP&P Reliability Improvement Report, August 2011” contained within Exhibit A-50 (JRA-4). In summary, more forestry line clearing provides greater system reliability to the benefit of customers. 4 TR 875-876.

Benchmark studies show the average level of line clearing utilized by North American electric utilities is an approximate 4-year effective clearing cycle or 25% of their system per year. 4 TR 876. Mr. Reasoner’s recommended level of $41,237,273 of forestry O&M expense equates to an approximate 10-year effective clearing cycle or approximately 10% clearing of the Company’s LVD system. 4 TR 876. This effective clearing cycle is over twice as long as the industry average and does not address the fact the effective clearing cycle is not keeping up with tree growth. 4 TR 875, 876. The level of forestry O&M expense proposed by Mr. Reasoner provides an effective cycle length that is far longer when compared to other North American electric utilities and will not support significant improvements relative to the IEEE reliability performance benchmarks discussed in Mr. Reasoner’s testimony at 5 TR 1149-1151. 4 TR 878.

It is not reasonable to expect the Company’s overall system reliability performance to improve without increasing the most impactful program the Company has to reduce customer interruptions. 4 TR 878. Therefore, the Company is requesting the Commission approve $53,000,000 for forestry O&M expense in order to allow for a program level of approximately 12.5% per year on the LVD system (an approximate 8-year effective clearing cycle), in order to address tree conditions at a rate greater than tree growth and in order to begin to make more significant and necessary improvements in overall system reliability to the benefit of customers. 4 TR 875, 878. See Appendix D, line 2.
c. **Areas of Dispute with the Attorney General**

Consumers Energy requests the Commission reject Attorney General witness Coppola’s proposed forestry spending level of $42,000,000. Mr. Coppola suggests Test Year forestry spending levels should be based on the average of the amounts spent during the 3-year period from 2009 to 2011. 4 TR 884. As with MPSC Staff witness Reasoner, Mr. Coppola’s rationale in determining his proposed forestry spending is not based on what is actually needed and necessary to make significant improvements in reliability over time, but rather based on recent spending levels. 4 TR 884. As discussed previously in this Brief, the Company is requesting to increase its forestry program to $53,000,000 to move the program level up to approximately 12.5% per year on the LVD system (an 8-year effective clearing cycle) in order to begin to make more significant and necessary improvements in overall system reliability for the benefit of customers. 4 TR 884-885.

Mr. Coppola’s recommended forestry program is strictly based on historical spending levels and neither reflects what is needed and necessary to improve overall system reliability nor does it consider industry benchmarks and practices. 4 TR 885. The Company requests the Commission reject Mr. Coppola’s recommendation.

**d. Areas of Dispute with MCAA**

Consumers Energy requests the Commission reject MCAA witness Peloquin’s request for a tracker-type mechanism for forestry expenses. As testified to by Company witness Ronn J. Rasmussen:

“As described earlier, the Company believes trackers are necessary only for significant expenses that are volatile, difficult to predict and beyond the Company’s ability to control. Forestry expenditures do not meet this criterion; therefore, the Company does not support Mr. Peloquin’s recommendation for a tracking mechanism.” 3 TR 105.
Since forestry expenses can be effectively managed and planned for by the Company, the Commission should reject Mr. Peloquin’s request for a forestry expense tracker.

2. **Fossil and Hydro Generation O&M Expense**

   a. **Company’s Position**

   Company witness David B. 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 $176,366,000. 6 TR 1306; Exhibit A-28 (DBK-3). The Test Year Base O&M was calculated using a linear regression which results in annual increases of 2.25%. 6 TR 1307. Projected expenses were adjusted for: 1) Selective Catalytic Reduction (“SCR”) (excluding urea);[^14] 2) Pulse Jet Fabric Filter Operation;[^15] 3) High Energy Piping Systems (“HEPS”) and Flow Accelerated Corrosion (“FAC”);[^16] and 4) Major Maintenance. 6 TR 1307. As explained by Mr. Kehoe, the Company tracks the historical and future maintenance needs of each generating unit. 6 TR 1310. 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 1310-1311.

   Mr. Kehoe explained that O&M expense spending in the generation area is split into “Base” and “Major Maintenance” components. 6 TR 1311. The Base O&M costs are determined by each generation unit’s operating history and are broken down into labor and

[^14]: Exhaust gases flow through the Selective Catalytic Reduction technology which converts NOx into inert nitrogen. 6 TR 1307. Beginning in 2008, Consumers Energy began operating the SCRs year round to meet the new NOx emission reductions standards that are required by the Clean Air Interstate Rule (“CAIR”). 6 TR 1307.

[^15]: The filters, when combined with Activated Carbon Injection, collect mercury and other hazardous air pollutants. 6 TR 1308. This equipment insures compliance with the Michigan Mercury Rule. 6 TR 1308.

[^16]: In 2009 and beyond, Consumers Energy is increasing testing at all steam plants in an effort to reduce the likelihood of a high pressure pipe failure due to the deterioration of pipe integrity. 6 TR 1308.
non-labor components. 6 TR 1311. Base O&M costs are fairly predictable. 6 TR 1311. Major Maintenance costs are not consistent and vary each year by generating unit. 6 TR 1311.

Major Maintenance is further divided into Outage and Non-Outage classifications. 6 TR 1312. 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 1312. The Company has scheduled two turbine outages during the Test Year, Whiting 1 and Whiting 2. 6 TR 1313. 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 1313. Mr. Kehoe listed the Non-Outage maintenance scheduled for the Test Year at 6 TR 1313-1314.

The requested O&M expenses are necessary and reasonable to continue Consumers Energy’s successful operation of the generation fleet. 6 TR 1315. Despite operating the oldest regulated generation fleet in the nation, Consumers Energy’s cost to generate electricity was ranked in the top 25% (i.e., least expensive) in the nation. 6 TR 1315.

b. **Areas of Dispute with Staff**

Consumers Energy requests the Commission reject Staff witness Rusnak’s proposal to remove O&M expenses above the base O&M spending for the smaller generating plants, namely J.R. Whiting units 1 through 3 and B.C. Cobb units 4 and 5. 6 TR 1340. Staff’s Fossil and Hydro Generation jurisdictional O&M expense level of $164.836 million understates the appropriate level of O&M expense by $11.5 million. See Appendix D, line 4.

Ms. Rusnak’s proposal is based on the permit for the installation of the Clean Coal Plant which required retirement of up to seven of the Company’s oldest plants. 6 TR 1340. However, the permit in Appendix D (item number 2) of the PTI No. 341-07 states, “If the CON is not approved or for any reason the Project is not constructed and operated, the commitment to
retire existing units under this Agreement becomes null and void.” 6 TR 1341. Since the Clean Coal Plant has been cancelled, there is no retirement obligation for these units. 6 TR 1341.

On December 2, 2011, Consumers Energy announced plans that provide for continued operation of the Company’s seven smallest coal-fired units through December 31, 2014 – at which time they will be “mothballed”. 6 TR 1341. The units that will be mothballed include the Whiting units 1 through 3, the Cobb units 4 and 5, and the Weadock units 7 and 8. 6 TR 1341. “Mothballed” refers to removing the generating unit from operations for the present, but maintaining the unit in a physical state such that it can become operational at a future date if circumstances exist justifying such action. 6 TR 1341. The Company is mothballing these units based on an evaluation of installing Air Quality Control Systems (“AQCS”) on the entire generating fleet to comply with proposed emissions regulations. 6 TR 1341. After analysis, it was determined that installing AQCS on the seven smaller units did not currently appear to be the most cost-effective action. 6 TR 1341.

The level of proposed O&M (and capital) expenditures requested in this proceeding is not affected by the plan to mothball the seven small generating units on January 1, 2015. 6 TR 1342. The Company’s filing in this case only seeks recovery of the O&M (and capital) required to safely operate these plants and comply with existing environmental regulations until the planned mothballing in 2015. 6 TR 1342. Consumers Energy is not seeking recovery of costs that contemplate operation beyond that date. 6 TR 1342.

The O&M expense for the seven smaller units for 2011 and 2012 included in the Company’s filing are necessary in order to allow the units to be utilized through the end of 2014. 6 TR 1342. The Commission should approve the proposed capital and O&M expenditures for the following reasons: 1) in the near term, these sites will continue to produce competitively
priced energy (based on modeling performed by Consumers Energy) through 2014 and there are significant benefits to our customers in continued operation of these units until 2015; 2) continued operation until 2015 will insure system reliability and stability; and 3) continued operation until 2015 will allow Consumers Energy to initiate and carry out a plan which minimizes the impact of these actions on all affected parties, including the completion of system impact studies that are required by Midwest Independent System Operator (“MISO”). 6 TR 1342-1343.

c. **Areas of Dispute with the Attorney General**

Consumers Energy requests the Commission reject Attorney General witness Coppola’s recommended $13.3 million reduction to O&M. Mr. Coppola arrives at this number by proposing a reduction in Base O&M by $6.5 million and a reduction in Major Maintenance expense by $6.8 million. 6 TR 1344.

Mr. Coppola states he arrived at his proposed $6.5 million Base O&M reduction by increasing the 2011 expense level by 1.5% over the 2010 amount and then not providing for any increase for 2012. 6 TR 1344. In contrast, Mr. Kehoe calculated Base O&M expenses using a regression analysis that results in annual increases of 2.25%. 6 TR 1345. Mr. Coppola himself acknowledged that historical Base O&M has increased from 2006 to 2011 at a yearly rate of 2.9%. 6 TR 1345; Exhibit AG-7; 4 TR 688. Mr. Coppola did not question any specific projects or expenditures and did not provide any basis for his position of no increase in Base O&M from 2011 to 2012. 6 TR 1345. The Commission should reject Mr. Coppola’s recommendation concerning Base O&M as he ignores the fact that Consumers Energy’s costs (labor and materials) continue to increase and even according to his own research and testimony, base O&M has risen at an average annual rate of 2.9% between 2006 and 2011. 6 TR 1345.
Mr. Coppola bases his $6.8 million Major Maintenance O&M reduction on a 3-year average of expenses (2009-2011). 6 TR 1346. Mr. Coppola fails to take into account the work that is scheduled to be performed and the expenses that will be incurred in the Test Year. 6 TR 1346. Furthermore, Mr. Coppola provides no support for his recommendation of a 3-year average, merely suggesting that it would be “more appropriate.” 6 TR 1346. As testified to by Mr. Kehoe, Major Maintenance O&M costs are not consistent, and vary each year by generating unit. 6 TR 1311. Consumers Energy is proposing Major Maintenance funding based on a group of specific projects that are planned rather than just using an average of an arbitrary number of years, thus the Commission should reject Mr. Coppola’s recommendation. 6 TR 1346.

d. Areas of Dispute with NRDC/MEC

Consumers Energy requests that the Commission reject NRDC/MEC witness Richards’ recommendation to reduce Base O&M Expense by $4,281,000. Ms. Richards calculates this amount by using a simple trend analysis to project future costs in the Test Year. 6 TR 1354. Ms. Richards makes two errors in her recommendation. First she claims, without support, that the use of a regression model that uses only three data points to predict future values is an insufficiently large sample, and therefore Consumers Energy’s regression model is not statistically valid. 6 TR 1354. Ms. Richards does not provide any evidence which supports her opinion that simple trend analysis is statistically more accurate than Linear Regression modeling. 6 TR 1355. Secondly, Ms. Richards made a mistake in her undocumented calculations. When duplicated by Mr. Kehoe, the number actually comes out to be 2.18%, not the 1.81% mistakenly calculated by Ms. Richards. 6 TR 1355.

Given that Ms. Richards’ claims are unsupported and her calculations are incorrect, the Commission should reject Ms. Richards’ suggestion that Consumers Energy has overstated Base O&M expenses by roughly $4,281,000. 6 TR 1356.
3. **Energy Supply O&M Expense**

   a. **Company’s Position**

   Company witness Ronk testified concerning the test period O&M expense for the electric portion of the Energy Supply Department. See, 3 TR 301-307; Exhibit A-35 (DFR-1). The electric portion of the Company’s Energy Supply Department consists of the following functional units: Fossil Fuel Supply, Transactions and Resource Planning, Transmission and Regulatory Strategy, Wholesale Settlements and Support, Electric Sourcing and Transactions, and Business Support. The operational responsibilities of each of these functional units is described in Mr. Ronk’s testimony. The O&M expense projected for the test period for Energy Supply O&M expense is $9,984,000. See Exhibit A-35 (DFR-1), line 6, column (e). See also, Appendix D, Tab Other O&M, line 5.

   The MPSC Staff accepted the Company’s projected O&M expense for this department. See, Exhibit S-3, Schedule C5 (Brian Welke), page 1 of 1, line 5.

4. **Corporate Service O&M Expense**

   a. **Company’s Position**

   Company witness Kenneth C. Jones, Assistant Controller, testified concerning the Corporate Services O&M projections. Mr. Jones calculated the projected Test Year O&M for the Corporate Services Departments to be $30,085,000, which was calculated from the 2010 actual of $28,332,000 and the 2011 projection of $29,895,000. 4 TR 957; Exhibit A-25 (KCJ-4). The Test Year O&M was calculated by using the 2010 actual expense and then applying inflation factors for labor and non-labor not to exceed the Consumer Price Index. 4 TR 957, 958. In addition, operation efficiencies and specific line item increases or decreases were included as appropriate. 4 TR 957, 958-959.
Corporate Services O&M expense includes expenses for Human Resources and Administrative Services, Internal Control & Compliance, Legal, Corporate Risk Management, Corporate Secretary, Governmental/Public Affairs and Corporate Compliance, Investor Relations and Treasury, Controller’s Area, Rates and Regulation/Regulatory Affairs, Corporate Tax, Financial Planning, General Activities and Administrative and Other. 4 TR 953-955.

Consumer’s Energy’s Corporate Service’s O&M expenses are reasonable, a conclusion supported by the fact that SNL Datasource\(^{17}\) ranked the electric side of Consumers Energy’s administrative and general costs (excluding Pension and Benefits) third lowest out of 61 electric companies with over 500,000 customers. 4 TR 959.

b. **Areas of Dispute with Staff**

Consumers Energy requests the Commission reject Staff witness Welke’s proposed reduction of $2,005,000 (5 TR 1200) to Corporate Services O&M. 4 TR 975. Mr. Welke’s calculation of the Test Year O&M did not take into consideration normalizations for unusual and/or one-time debits or credits which are not expected to continue as part of ongoing expenses. 4 TR 975. These various one-time adjustments and disallowances significantly affect the level of O&M expenses.\(^{18}\) 4 TR 975. Mr. Welke’s method of merely multiplying the total corporate services expense as of June 30, 2011, by inflation factors is unreliable as significant one-time events are not taken into account and is inconsistent with the calculations ordered by the Commission in Case No. U-16191. 4 TR 975; 976. Consumers Energy requests the Commission reject Mr. Welke’s proposed reduction.

\(^{17}\) The SNL Datasource is maintained by SNL Financial LC. SNL Datasource provides financial and operating data for electric utility companies. 4 TR 960.

\(^{18}\) Exhibit A-L5 (KCIJ-4) lists the various normalizations and disallowances that must be taken into account as one-time events when generating a historical average.
c. **Areas of Dispute with the Attorney General**

Consumers Energy requests the Commission reject Attorney General witness Coppola’s proposed reduction of $1.8 million to Corporate Services O&M. Mr. Coppola proposes that corporate wages remain at 2010 levels, with no adjustments. 4 TR 693. The Company included modest wage increases of 3.0% and 2.5% for 2011 and 2012 within its filing, consistent with the labor market for 2011 and 2012. 3 TR 112. If the Company does not maintain salaries at competitive levels it risks losing highly skilled employees to other companies. 3 TR 112. The training expense as well as loss of productivity of these employees would be greater than the cost of maintaining salary levels that are comparable to the labor market. 3 TR 112. There is nothing unreasonable about compensating employees at market levels, which is what the evidence shows is being done. Consumers Energy requests the Commission reject Mr. Coppola’s proposed reduction.

5. **Uncollectible Expense**

a. **Company’s Position**

Company witness Kenneth C. Jones, Assistant Controller, testified concerning the Company’s uncollectible expense. According to Mr. Jones, uncollectible 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. 4 TR 960; Exhibit A-23 (KCJ-2). The Commission adopted an Uncollectible Expense Tracking Mechanism (“UETM”) 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. 4 TR 960-961. The amounts recovered through the UETM were not included when calculating the uncollectible expense for 2011 and 2012. 4 TR 961.
Included in the uncollectible expense calculation is an adjustment to reflect the substantial reduction in funding for the LIHEAP. 4 TR 961. Funding cuts in LIHEAP at the federal level will result in a 50% reduction in funds available to the Company’s customers. 4 TR 961. This in turn reduces funds available to customers to pay their electric bills, impacting the Company’s uncollectible expense. 4 TR 978. The impact of the funding cuts to LIHEAP is calculated in Exhibit A-23 (KCJ-2). Including the LIHEAP adjustment, Mr. Jones has calculated an uncollectible expense of $32,346,000 for the Test Year. Exhibit A-23 (KCJ-2); 4 TR 962-963.

b. Areas of Dispute with Staff

Consumers Energy requests the Commission reject Staff witness Welke’s proposed reduction of $13,542,000 (5 TR 1200) to the Company’s uncollectible expense. This is comprised of a reduction of $12,942,000 related to LIHEAP and a reduction of $600,000 related to PeopleCare. 5 TR 1202. The Company requests that the level of uncollectible expense should be set at $32,346,000 as shown on Appendix D, line 14.

Mr. Welke bases his proposal on his opinion that any reduction to LIHEAP would only affect the gas division of Consumers Energy and not the electric division. 4 TR 977.

As explained by Mr. Jones, a reduction in LIHEAP funding does impact the electric business. 4 TR 977. LIHEAP provides funding for Home Heating Credits (“HHC”) and State Emergency Relief (“SER”) energy services. 4 TR 978. HHC and SER funds can both be used by customers to pay their electric bills. 4 TR 978.

The inadequacy of Mr. Welke’s proposed uncollectible expense is evidenced by the Company’s actual uncollectible experience in 2011. 4 TR 979. The Company’s 2011 11-months actual uncollectible expense is $24,075,000. 4 TR 979. When the projected electrical uncollectible expense for the month of December 2011 ($2.6 million) is added to the
2011 11-months actual uncollectible expenses, the total is $26.6 million for fiscal year 2011. 4 TR 979-980. This compares to Mr. Welke’s forecast of $19.4 million, a $7.2 million difference. 4 TR 980. This difference does not include any LIHEAP adjustment which will impact the 2012 uncollectible expenses. 4 TR 980. Thus the actual 2011 numbers support the Company’s position concerning a higher level of uncollectible expenses especially when the impact of LIHEAP is factored in. 4 TR 980.

A reduction to LIHEAP funds affects electric customers as funds can be used to pay for electric usage and funds also impact the disposable income of electric customers. 4 TR 978. The Company has already seen a jump in electric uncollectible expenses beyond what was even forecasted. 4 TR 980. The Commission should not reduce the amount of uncollectible expense as proposed by Mr. Welke as the LIHEAP reduction will impact the Company’s uncollectible expense and the Company’s projected uncollectible expense number is much closer to the actual uncollectible expense as evidenced by 2011 actual numbers. 4 TR 978; 4 TR 980.

Staff witness Welke also proposes to remove $600,000 from the Company’s proposed uncollectible expense related to PeopleCare contributions based on his conclusion these expenses place ratepayers in the position of becoming involuntary contributors to charity.19 Mr. Welke’s characterization of recovery of PeopleCare through rates as “charity” is incorrect. The Company applies PeopleCare contributions to qualifying customers’ accounts in the form of bill credits. 3 TR 111. The Company’s contributions to and promotion of the PeopleCare program allow the Company to access additional contributions from its employees, customers, and outside agencies. 3 TR 111. Collectively, these contributions effectively reduce

---

19 Staff witness Bankapur’s proposed PeopleCare adjustment is discussed in Section III.B.2. of this Brief, working capital.
uncollectible expense, therefore, ratepayers don’t incur incremental costs as a result of this program. 3 TR 111. The absence of funding of this program would result in higher uncollectible account write-offs and lead to more shut-offs. 3 TR 111. If the Commission were to deny recovery of these contributions through rates, it would jeopardize future contributions to an extremely worthwhile and beneficial program that assists the Company’s most at-risk customers, and ultimately lead to higher overall uncollectible expenses.

c. Areas of Dispute with the Attorney General

Consumers Energy requests the Commission reject Attorney General witness Coppola’s proposed elimination of any LIHEAP adjustment to the Company’s uncollectible expense. As discussed above in response to Staff’s position, the Commission should not reduce the amount of uncollectible expense as proposed by Mr. Coppola as the LIHEAP funding reduction will impact the Company’s uncollectible expense and the Company’s uncollectible expense number is much closer to the actual uncollectible expense as evidenced by 2011 actual numbers. 4 TR 978; 4 TR 980.

6. Injuries and Damages Expense

a. Company’s Position

Company witness Kenneth C. Jones, Assistant Controller, testified concerning the Company’s injuries and damages expense. According to Mr. Jones, electric injuries and damages include liabilities that arise in the normal course of Company business for various types of items such as lawn, fence, and driveway damage (property damage), accidents and lawsuits (liability damages), and workers’ compensation costs. 4 TR 963. The injuries and damages expense was calculated by using a 5-year average of property and liability damages increased by inflation factors for the years 2011-2012 and adding in legal costs (using the 2010 amount and
increasing for inflation) and adding in workers’ compensation costs (using the 2010 amount and increasing for inflation). 4 TR 964; Exhibit A-24 (KCJ-3). The results of this calculation are an injuries and damages expense of $4.985 million for the Test Year. 4 TR 963; Exhibit A-24 (KCJ-3).

b. Areas of Dispute with Staff

Consumers Energy requests the Commission reject Staff witness Welke’s proposed reduction of $1,105,000 to the injuries and damages expense. When calculating the injuries and damages expense, Mr. Welke improperly used a 5-year average of all of the components of the injuries and damages expense. 4 TR 981. A 5-year average is appropriate for expenses that are volatile in nature, such as the property and liability damages expense. However, a 5-year average is not appropriate for the more predictable internal legal costs and workers’ compensation costs. 4 TR 981. Mr. Welke’s use of a 5-year average for all components produces an unrealistically low starting point for the expense calculation and has not been used in previous cases. 4 TR 981. The methodology used by Mr. Jones has been used and accepted in previously filed rate cases. 4 TR 981. Additionally, Mr. Welke did not use proper inflation factors thus creating an even larger error in his calculation. 4 TR 981.

The Commission should reject Mr. Welke’s reduction to the injuries and damages expense and continue to accept the methodology that has been used in the past when calculating this expense. Consumers Energy requests the Commission adopt an injuries and damages expense of $4.985 million as shown on Appendix D, line 15.
7. **BTS O&M Expenses**

   **a. Company’s Position**

   Company witness Leslie E. Roth, Director of Enterprise IT Governance, (who adopted the testimony of Karen Beers), testified concerning the O&M projections for the BTS Department. Exhibit A-15 (KMB-1) shows the expense levels for each major category. The projected O&M expense for this department is $30,060,000 in 2010; $32,766,000 in 2011; and $32,834,000 for the Test Year (12-months ended September 30, 2012). 3 TR 560; Exhibit A-15 (KMB-1). These projections were based on a 2010 actual amount taken from the Company’s records. 3 TR 560. The 2011 O&M, while 9% higher than 2010, is 11.7% lower than what would have been calculated using inflation from the 2009 O&M amount. 3 TR 561. The Test Year O&M reflects only a 0.2% increase for inflation from calendar year 2011 for labor and materials. 3 TR 561. The Company is projecting continued reductions from the 2009 historical expense level as the reliance on higher cost external resources to support SAP has lessened. 3 TR 561. The only increases are inflationary increases for labor, outside services and materials and all are reasonable O&M projections for the BTS Department. 3 TR 561.

   **b. Areas of Dispute with Staff**

   Consumers Energy requests the Commission reject Staff witness Welke’s proposed $664,000 reduction in BTS O&M. Mr. Welke’s calculation of the Test Year O&M is based on his projection of 2010 O&M expense using numbers more current than in the Company’s preliminary filing. 3 TR 574. However, when even more current numbers are used (expenditures as of September 30, 2011) the result is $499,000 higher than Mr. Welke’s projection. 3 TR 575. This calculation is shown in Exhibit A-66 (LER-1). For ratemaking purposes, Consumers Energy requests the Commission approve an O&M amount for the test
year of $32,834,000, as shown on Exhibit A-15 (KMB-1), and Appendix D, line 6, and reject Mr. Welke’s proposed reduction.

c. Areas of Dispute with the Attorney General

Consumers Energy requests the Commission reject Attorney General witness Coppola’s recommendation for either a $14,500,000 or a $14,200,000 reduction in the BTS Department’s O&M expenses for the test year. Both reductions are based on Mr. Coppola’s claim of inadequate proof of labor savings due to the implementation of SAP. 4 TR 691.

Mr. Coppola calculates his proposed $14.5 million reduction by taking one-half of his calculated theoretical cost savings to customers of $29 million due to the implementation of SAP. 4 TR 691-692. Obviously, the various efficiencies and improved customer service derived from implementing SAP are already included within operating plans and budgets of the Company’s departments (starting in 2006) and thus the Company’s requested rate relief. 3 TR 579. It would be inappropriate to double count these savings by imposing a second additional reduction as suggested by Mr. Coppola.

As an alternative, Mr. Coppola suggests the Commission eliminate the remaining book value of the SAP project ($127,000,000) from the rate base and then take the corresponding revenue deficiency reduction of $14,200,000 as a reduction to BTS O&M expense. 4 TR 692; 3 TR 577. Again, Mr. Coppola’s suggestion is based on his claim there is not sufficient evidence of quantifiable financial benefits for the implementation of SAP. 4 TR 692. In essence, Mr. Coppola is attempting to disallow, after the fact, an approved program. In Case No. U-16191, the Commission reviewed and found reasonable the capital expenditures related to SAP. 3 TR 575.
Mr. Coppola’s main complaint is about the sufficiency of evidence showing quantifiable financial benefits. 4 TR 692. What Mr. Coppola fails to appreciate is that along with creating efficiencies and cost savings within the Company, SAP was needed to replace various legacy systems. Page 1 of Exhibit A-17 (KMB-3) shows the myriad of old legacy systems that were in place prior to SAP. 20 There were over 150 legacy systems, all over 35 years in age. 3 TR 577. The programming language was obsolete and written for a 1970s technology platform. 3 TR 577-578. While no specific savings dollars were calculated concerning having a functioning, integrated system (SAP) verses a failing, obsolete system (legacy systems), the actual cost of not having a workable computer system would be enormous. As the Commission has recognized in past rate cases, it was becoming impractical to attempt to operate the Company’s utility businesses relying on old existing legacy systems. 3 TR 578.

The many benefits of SAP to the Company include a reduction in operational issues, work simplification, reductions in manual work and task hand-offs, and improved accuracy and timeliness. 3 TR 578. Customer benefits include increased access to comprehensive, real time customer information, and better handling of customer calls. 3 TR 578. It is for these reasons the Commission ultimately approved recovery of the costs identified for implementing SAP in its final orders in Case No. U-15245 and Case No. U-15645. 3 TR 578.

The effect of Mr. Coppola’s proposal would be to reduce the test year BTS Department O&M request by nearly 50%. 3 TR 575. Any attempt to operate within the constraints of such a reduction would have significant, adverse effects on the Company and its customers including the ability to respond to customer calls, the ability to restore service to customers, the ability to maintain computer and radio systems, and the ability to maintain current

---

20 Page 2 of Exhibit A-17 (KMB-3) shows the Company’s computer landscape after the implementation of SAP.
software. 3 TR 576. There would be many business, customer and safety issues that would arise from such a drastic reduction. 3 TR 576.

The implementation of SAP was largely a matter of business necessity, and attempting to compile a list of specific financial impacts would be misleading in evaluating the merits of SAP. 3 TR 579. Mr. Coppola’s suggested reduction should be rejected by the Commission.

8. **Employee Benefits**

a. **The Company and Staff Are in Agreement**

Company and Staff witnesses were in agreement that the appropriate total electric test year O&M expense level for employee benefits should be set at $106,991,000. See Exhibit A-32 (HBK-1) and Exhibit S-3, Schedule C5, line 8. This test year employee benefit O&M expense amount is comprised of: (i) $40.638 million of Pension Plan expense; (ii) $3.931 million of Defined Company Contribution Plan (“DCCP”) expense; (iii) $6.721 million of 401(k) savings plan expense; (iv) $30.451 million of active employee health care, life insurance, and long-term disability insurance (“LTD”) expense; and (v) $25.250 million of retiree health care and life insurance expense. These employee benefits expenses are shown on Appendix D to this Brief on lines 8-12.

The Company presented the testimony of Herbert B. Kops, Director of Employee Benefits, to provide support for the Company’s electric expenses related to the pension, DCCP, 401(k) savings, health care, life insurance, and LTD plans provided to its active employees and retirees. 3 TR 408-456. Mr. Kops is responsible for the design, implementation, and administration of the Company’s retirement benefit and insurance benefit plans for employees and retirees. He also has responsibility for administration of the Company’s self-insured workers compensation program, the relocation plan, and the educational assistance program. 3 TR 409.
Exhibit A-32 (HBK-1) summarizes the electric O&M expenses for these retirement and insurance benefit plans.

Pension expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets, and certain other actuarial assumptions. 3 TR 414-415. Pension Plan 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”) (formerly known as Financial Accounting Standards 87) using information specific to the Company’s Pension Plan. 3 TR 414-415. Actuarial assumptions are reviewed by the Company’s auditors to insure consistency with Generally Accepted Accounting Principles (“GAAP”). 3 TR 414. Mr. Kops testified the Company made a cash contribution to the Pension Plan in 2010 totaling $375 million. 3 TR 416. He stated the contribution was made to ensure the funding percentage level continues to increase as required under the Pension Protection Act and so that benefit restrictions from at-risk status are not placed on the Plan because funding status is below 80%. 3 TR 416-417. This large pension contribution in 2010 was the primary reason that pension expense declined in 2011. 3 TR 417.

In order to remain competitive in the area of a benefits package that attracts and retains qualified and talented employees, on September 1, 2005, the Company replaced the defined benefit Pension Plan with the DCCP for all new hires. 3 TR 419. All employees hired on and after September 1, 2005 participate in the DCCP as part of their retirement package. 3 TR 419. The Company makes a contribution to the DCCP equal to 6% of base wages for employees participating in the DCCP. 3 TR 420. Mr. Kops stated that the DCCP contribution will continue to grow as all new employees will participate in the program. 3 TR 420. Mr. Kops testified that, in addition, the contribution amount is higher in 2011 than 2010 as a result of an
increase in the DCCP contribution from 5% to 6% to keep retirement benefits competitive with the market. 3 TR 421-422.

The 401(k) Savings Plan is a 401(k) type retirement savings program funded by employee contributions. 3 TR 423. The Company matches 60% of the first 6% of employee contributions. 3 TR 423. Mr. Kops testified that the employer matching program is important to helping to provide a competitive benefit package needed to attract and retain qualified and talented employees. 3 TR 424. He noted 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. 3 TR 425.

Mr. Kops also addressed active and retiree health care, life insurance, and long-term disability expense. Mr. Kops testified that health care costs are increasing at a level higher than inflation due to numerous factors outside the Company’s control. 3 TR 432-433. To help mitigate cost increases, the Company has implemented a number of plan changes, including sharing cost increases with employees and retirees, introducing education programs addressing the use of health care benefits, and the promotion of preventive services. See 3 TR 434-448, 455-456. The expenses for active employees are based upon actual costs for these benefits that have been incurred or are expected to be incurred. 3 TR 427. The expenses for retirees are determined using actuarial analysis in accordance with Accounting Standards Codification (“ASC”) 715 (formerly known as Statement of Financial Accounting Standards 106). 3 TR 427-428, 449-456. Retiree Health Care and Life Insurance costs have decreased over the past several years and are projected to further decrease during the test year ending September 30, 2012. 3 TR 455-456, Exhibit A-32 (HK-1).
b. **Areas of Dispute with the Attorney General**

As discussed above, Retiree Health Care and Life Insurance expense, sometimes referred to as Other Post-Employment Benefits ("OPEB") expense, is determined actuarially based upon established Generally Accepted Accounting Standards. Attorney General witness Coppola does not challenge the actuarial analysis or determinations but, nevertheless, argues that the employee benefit O&M expense should be decreased by $4.2 million and capital expenditures by $2.7 million. Mr. Coppola argues that this reduction is warranted based on the argument the Company should have contributed more to OPEB Plan funding during the historical period 2005-2010. 4 TR 698-699. His reasoning is not valid and his proposed reduction in O&M expense and capital expenditures is unwarranted.

The appropriate level of expense to be included in rates is the actuarially determined expense level. The provisions of GAAP, ASC 715 describe the methodologies and assumptions required to properly calculate and account for retiree health care and life insurance expense. 3 TR 449-450. The expense amounts supported by Company and Staff witnesses were calculated in accordance with ASC 715 using information specific to the Company’s retiree health insurance and life insurance plans. 3 TR 453. Making a downward adjustment to retiree health care and life insurance expense in this case based on an imputed impact derived from an alternative historical funding approach would not be reasonable or appropriate and, indeed, was rejected by the Commission when Mr. Coppola made the same argument in Detroit Edison’s recent electric rate case, Case No. U-16472, *et al*.

In its October 20, 2011, order in Detroit Edison Case No. U-16472, *et al*, the Commission stated:

“The ALJ agreed with the Staff and Detroit Edison that the Attorney General’s proposed reduction to OPEB expense should be rejected. He noted that the disparity pointed out by the
Attorney General was significantly overstated. And, he found that
the Attorney General failed to account for the effect on working
capital that would result from the funding he proposed.

. . . The ALJ recommended that the Commission decline to attempt
to recoup previous underfunding, but should, on a going forward
basis, direct Detroit Edison to fund the entire portion of OPEB
expense included in rates, not the amount net of capitalization.

* * *

The Commission finds that the ALJ’s recommendation is
supported by Commission precedent, the record in this case, and
does not violate any due process rights of the utility.

* * *

At this juncture, the Commission will not attempt to rectify the
underfunding from the past. Detroit Edison may be held
responsible for making up the difference when the liability
becomes due. However, on a going forward basis, the Commission
directs Detroit Edison to place in an external fund an amount
sufficient to cover OPEB costs recognized in its rates, without
reduction for capitalized or deferred amounts.” October 20, 2011
order, pp. 59-60, 62, 64.

Consumers Energy witness Theodore Vogel presented rebuttal to Mr. Coppola’s
arguments in the current Consumers Energy case at 3 TR 630-633. Mr. Vogel is Vice President
and Chief Tax Counsel for Consumers Energy. 3 TR 612. Mr. Vogel testified:

“First, Mr. Coppola is incorrect in asserting that the Company
should have contributed approximately 23% more, or about $80
million for the total company, to the OPEB plan over the 2005 to
2010 period. Second, Mr. Coppola’s proposed reduction to O&M
and capital is an inexplicable calculation devoid of any logical
connection to test year expenses or ratemaking concepts. Finally,
Mr. Coppola has failed to take into account offsetting ratemaking
effects from increased OPEB funding, principally from an increase
in working capital, that would more than offset the revenue
requirement effect of the hypothetical reductions in O&M expense
and capital that he proposes.” 3 TR 630-631.

Mr. Vogel stated Mr. Coppola’s proposed reduction did not make logical sense from any
financial, economic, accounting, or ratemaking perspective and that the result of Mr. Coppola’s
suggestions, in actuality, would be to increase rates rather than decrease rates. 3 TR 631, 632-633.

Mr. Vogel testified that Consumers Energy’s historical understanding was that funding requirements were limited to OPEB costs included in rates as O&M expense, with capitalized OPEB amounts funded in the future based on recovery through depreciation. 3 TR 631. Mr. Vogel testified he was aware of the Commission’s order in Case No. U-16472 involving Detroit Edison and Consumers Energy will adjust its funding accordingly on a go forward basis:

“I understand that the Commission considered, and rejected, similar proposals made by Mr. Coppola in that case. However, the Commission ordered Detroit Edison on a going forward basis to place into an external fund amounts sufficient to cover both the OPEB expense and capitalized OPEB recognized in rates. The Company understands this to be the Commission’s current view regarding OPEB funding. Accordingly, the Company also is prepared, on a going forward basis starting in 2012, to fund its external OPEB trusts with the amount of OPEB expense and capitalized OPEB reflected in rates.” 3 TR 633.

Consistent with its decision in Case No. U-16472, et al, the Commission should reject the recommendation of the Attorney General’s witness in this current Consumers Energy case to reduce OPEB expense.

9. SG/AMI O&M Expense Items

a. Company’s Position

SGAMI has been summarized earlier. The Company’s Operating and Maintenance costs for the SG/AMI in the initial Application in this docket were $7.1 million for the projected test year. Exhibit A-48 (MKT-6), Summary of Projected Electric & Common O&M Expense, presents the O&M expenditures for the Smart Grid Program. The expenditures
are categorized in three cost groups: (1) Project Management & Other Common; (2) Customer Programs; and (3) Meters, Modules & Communications O&M. 3 TR 607.

The first activity is common to both the gas and electric automated metering infrastructure (AMI). As such, the figures here have been prorated to reflect only the electric portion. For each of the activities, the O&M expenditure is shown for calendar years 2009-2011 and 12-months ending September 2012. Page one shows total amounts for each of the years listed while page two shows total amounts for each of the years listed, plus the year-to-year change in O&M expenditure. 3 TR 608. These O&M expenditures are described in 3 TR 608-609.

However, the Company has revised its meter deployment plans to commence Phase 2 in September 2012 instead of March 2012. This was due to the timing of needed system modifications and smart meters available per Company specifications. See, Exhibit S-17. This deferred deployment schedule reduces the Company’s O&M requirements during the projected test year from $7.072 million to $4 million.

D. **Depreciation and Amortization Expense**

The difference between the revised jurisdictional depreciation and amortization expense of $361.8 million that Consumers Energy has calculated for the test year (see Exhibit A-8 (EAR-53a), Schedule C6a) and jurisdictional depreciation and amortization expense level of $333.7 million calculated by Staff (see Exhibit S-3, Schedule C6, Exhibit S-6, Schedule F1, p. 1, line 9) is attributable to two factors. Approximately $7 million of this difference is attributable to Staff not including amortization expense for the Clean Coal Plant. This issue is addressed in Section VI.D of this Brief. The remaining difference is attributable to Staff having calculated depreciation expense using depreciation rates that will be outdated when final rates are approved.
in this case rather than the depreciation rates that were approved in Case No. U-16054. 3 TR 186.

On June 28, 2011, the Commission approved a settlement agreement in Case No. U-16054 that provided the new depreciation rates would become effective with the final order in this next electric rate case. Paragraph 2 of the Settlement Agreement (Attachment A to the June 28, 2011 order) stated:

“2. The parties agree that the depreciation rates shown on Attachment 1 shall become effective at the same time new electric rates go into effect in Consumers Energy’s next general electric rate case following the issuance of a final order setting such rates.”

Consistent with this, the Commission in its order stated:

“According to the terms of the settlement agreement, attached as Attachment A, the parties agree that the Commission should approve the revised depreciation rates, attached as Attachment 1 to the settlement agreement . . . The new depreciation rates would become effective with the final order in Consumers’ next general electric rate case. . . .

The Commission finds that the settlement agreement is reasonable and in the public interest, and should be approved.

THEREFORE, IT IS ORDERED that:

A. The settlement agreement, attached as Attachment A, is approved.

B. The revised depreciation rates, attached as Attachment 1 to the settlement agreement, shall become effective with the final order in Consumers Energy Company’s next general electric rate case.” June 28, 2011 order, pp.1-2

Ms. Rolling testified:

“In order to capture the appropriate level of depreciation expense to include in rates when the new depreciation rates from the U-16054 Depreciation Case Settlement go into effect upon a final order in this case, a separate calculation of depreciation expense was necessary. The separate calculation of $354,595,000 jurisdictional depreciation expense, which excludes Clean Coal
Plant amortization ($361,816,000 including Clean Coal Plant amortization), represents an October 2011-September 2012 test year expense using the new depreciation rates from the U-16054 Depreciation Case Settlement. See Exhibit A-8 (EAR-53a), Schedule C6a. This is the appropriate level of expense for the test year in the Company’s revenue requirement calculation and results in approximately $20,393,000 additional jurisdictional depreciation expense.” 3 TR 187. (Emphasis added).

Once the new depreciation rates go into effect, the Company will begin to depreciate Plant-in-Service at the new depreciation rates, which will increase depreciation expense. 3 TR 187. If rates are set using the Staff’s depreciation expense, this will result in an expense level being reflected in the revenue requirement calculation that is lower than is being experienced during the time rates are in effect. 3 TR 188. Consumers Energy submits that the depreciation expense calculated on Exhibit A-8 (EAR-53a), Schedule C6a, should be used in setting rates so that rates will reflect the level of depreciation expense being expensed on the Company’s books.

E. Taxes

1. Property Tax

Theodore J. Vogel, Vice President and Chief Tax Counsel, testified on behalf of the Company concerning property tax. Mr. Vogel testified that the test period property tax expense is projected to be $136.2 million. 3 TR 616. Mr. Vogel set forth the methodology he used to reach that projection in his testimony, see, 3 TR 614-616.

Staff witness Talbert testified the Staff generally agreed with the methodology employed by the Company to calculate the components of general taxes. 5 TR 1189 (testimony of Staff witness Talbert). However, Staff disagrees with the amount of property tax, contending that the property tax should be reduced consistent with a reduction in CWIP. 5 TR 1189; Exhibit
S-2, Schedule B-1 (Staff witness Krause), line 7. However, as Company witness Vogel testified in rebuttal:

“[The] proposed CWIP adjustment should not have any impact on the test year property tax expense because the CWIP was not included in the Company’s test year property tax expense calculation. Under Michigan law, the Company will be assessed property taxes in 2012 by local units of government based on property as it exists on December 31, 2011. Property closed to plant in service by December 31, 2011, is included in the test year property tax expense calculation, subsequent CWIP is not. Further, much of the CWIP that [Staff witness] Mr. Krause proposes to disallow is pollution control equipment. Pollution control equipment is generally exempt from property taxes, and would not be included in the test year property tax expense in any event. Therefore, regardless of the merits of Mr. Krause’s CWIP adjustment, it is incorrect to reduce the Company’s test year property tax expense by $1.358 million as proposed by Ms. Talbert.” 3 TR 626.

2. Federal, Michigan, and Local Income Taxes

Staff witness Talbert also recommended a reduction in the Company’s test period federal income tax expense related to the domestic production activity deduction (the “DPA Deduction”). See, 5 TR 1190-1191. According to Staff, this deduction would result in a $1.987 million reduction in federal income tax. However, as Mr. Vogel testified in rebuttal, the DPA Deduction is not available to Consumers Energy Company and therefore should not be included in the calculation of test period federal income tax expense. As Mr. Vogel testified:

“Ms. Talbert imputes a hypothetical tax deduction where no such deduction actually exists. Although the tax deduction that Ms. Talbert refers to is provided by Section 199 of the Internal Revenue Code (‘IRC’), it is not a deduction that is available to Consumers Energy either on a separate company basis or as part of the CMS consolidated tax group. Consumers Energy does not have the option of filing its tax return ‘on a stand-alone basis.’ Consumers Energy has been part of a consolidated corporate income tax return since 1973. The IRC does not permit corporations to freely file on a consolidated or separate basis as they wish. The DPA Deduction is different from other deductions
allowed by the IRC in that it is created only on a consolidated tax return basis.” 3 TR 627.

Furthermore, even if this deduction were allowed, “there is considerable uncertainty as to how the deduction should be calculated.” Id. The amount proposed by Ms. Talbert is calculated “using a hypothetical tax deduction methodology that has not been accepted by the Internal Revenue Service.” 3 TR 627-628. In order to calculate the proper taxable income, it is necessary that “domestic production gross receipts” be separately determined. Since revenue of an integrated utility is generally from “bundled” rates, there are serious questions as to what portion of an integrated utility’s revenue would constitute “domestic production gross receipts.” See, generally, 3 TR 627-628. Consumers Energy therefore believes that the adjustments proposed by Ms. Talbert should not be included in the rates set by the Commission in this proceeding.

Attorney General witness Coppola, also criticizes certain facets of the Company’s tax presentation. Mr. Coppola proposes a reduction to property tax expense related to the Company’s SAP project in the amount of $3.9 million. Exhibit AG-8, line 4. However, as Company witness Vogel testified, no property tax expense was included in the Company’s tax presentation relating to computer software such as SAP. That is because software is “exempt from property taxation under MCL 211.9d.” 3 TR 630. Thus, no property tax expense was included in the Company’s test year relating to SAP. Since it was not present in the Company’s case, it would be incorrect to exclude any amount of property tax expense on account of the Company’s SAP program.

3. **Medicare Part D Subsidy Tax Issues**

Mr. Vogel also testified as to the Company’s increased tax costs resulting from the 2010 federal health care reform legislation. See, 3 TR 616 et seq. Under this new
legislation, the previously tax free nature of the Medicare Part D subsidy for payments received after 2012 was eliminated. Future subsidy amounts will now be subject to the 35% federal corporate income tax and related 6% Michigan corporate income tax. The Company’s test year calculation includes the impact of this loss of future tax benefit and the related recognition of a regulatory tax asset for taxes “which will be paid on the accrued Medicare Part D subsidy amounts.” 3 TR 616. No party opposed this proposal.

4. **Commission Tax Accounting Requests**

Company witness Vogel also presented certain requests for accounting approvals from the Commission. These requests are described in detail at 3 TR 620-621 and relate to certain temporary accounting required by the newly enacted MCIT [i.e., the newly-enacted Michigan Corporate Income Tax]. As Mr. Vogel testified, the accounting authority requested will account for temporary accounting differences caused by the new statute. Mr. Vogel has described the new statute and its impact on electric utility operations at 3 TR 621. No party opposed these requests.

**F. Allowance for Funds Used during Construction (“AFUDC”)**

The criteria for applying AFUDC to a construction project require on-site construction activities of more than six months duration and an estimated plant cost (excluding AFUDC) in excess of $50,000. 3 TR 179. Consumers Energy has calculated a jurisdictional AFUDC expense level of $2.0 million compared to Staff’s expense level of $1.9 million due to different assumptions regarding CWIP during the test year. If the Commission agrees environmental expenditures should be included in Rate Base (see Section III.B) then the AFUDC
should be set at $2.0 million. If the Commission does not agree environmental expenditures should be included in Rate Base, then $1.9 million should be used.21

G. Calculation of Adjusted Net Operating Income

Total revenues of the Company are $3,726 million. As shown in Appendix C, p. 1, after expenses net operating income is $412 million. Adjusting for AFUDC leaves an adjusted net operating income of $414 million. Appendix C, p. 1. Staff’s adjusted net operating income is calculated at $455 million. Appendix C.

VI. OTHER REVENUE AND ACCOUNTING ISSUES

A. Revenue Decoupling Mechanism/Revenue Tracker Proposal

Company witness Benjamin M. Ruhl described the Revenue Decoupling Mechanism (“RDM”) currently in place for the Company and the modifications to the RDM requested by the Company. Mr. Ruhl testified about the RDM as follows:

“Q. Please describe the electric RDM currently in effect as approved by the Commission.

A. The approved electric RDM is based on comparing the ‘actual’ change in usage per customer compared to the usage per customer that was used to establish rates. The change in usage per customer for each class is multiplied by the nonfuel rate for each customer rate class (as established in the most recent rate case) and the number of customers in that class to determine the revenue adjustment necessary to maintain the level of revenues approved in the most recent rate proceeding. The mechanism is symmetrical in that it may result in prospective refunds or collections of revenue depending on whether customers use more or less energy than average, which would increase or decrease the Company’s revenues during the decoupling period.

Q. What shortcomings do you believe exist with the current method?

A. The current method derives the change in usage per customer utilizing the customer levels from the most recent

21 Clean Coal Plant expenditures did not qualify for AFUDC treatment. 3 TR 214.
approved rate proceeding. Over the course of the effective period customer counts may change for various reasons. The approved decoupling mechanism does not recognize the migration of customers between rate schedules, which could introduce an element of distortion.

Q. What modification to the revenue decoupling mechanism is the Company proposing in this proceeding to address this issue?

A. The Company is proposing an RDM similar to that proposed in its recent gas rate proceeding, U-16418. This RDM is essentially a revenue tracker that stabilizes nonfuel rate revenues. The Company proposes to revise the RDM so that it simply 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 by rate class. The Company proposes that the decoupling be reconciled on an annual basis and continue up to the date the Commission issues a final order in the next electric rate case, which would then establish a new start date for the next decoupling period. The total net amount of the revenue shortfall or surplus for all rate classes would then be allocated to customers on the various rate schedules based on their share of non-fuel revenue as approved by the Commission in the most recent general rate case proceeding. An illustrative example of this mechanism is provided in my Exhibit A-41 (BMR-9).” 3 TR 240-241.

Mr. Ruhl explained the rationale for proposing the requested changes to the RDM already in place:

“Q. Why do you believe this modification to the revenue decoupling mechanism is necessary?

A. The modification being proposed by the Company eliminates the impact that the change in customer counts and potential of migration of customers between rates over the decoupling period has on the calculation of decoupled revenue. The goal of any decoupling mechanism is to eliminate the inherent disincentives that exist for a utility to reduce sales by actively promoting energy efficiency and implementing programs that reduce sales and revenue. The Company believes that the adoption of the proposed RDM modification would be effective in removing any disincentives to meet or exceed the statutory EO requirements.
Q. When does the Company propose that the modified RDM be implemented?

A. The Company believes that the modified RDM should be implemented beginning the first full billing month following the date of the Commission final order in this case. The Company proposes that the decoupling mechanism approved in Case U-16191 continue through the date of the final order in this case.” 3 TR 241-242.

Various parties opposed or criticized the Company’s RDM proposal. The MPSC Staff, through the testimony and exhibits of Katie Smith, criticized the Company’s proposal. See, 5 TR 1176 et seq. The Staff’s proposed Energy Optimization caps in the RDM would operate as a ceiling for the amount of revenue that the Company could recover, regardless of the actual deviation from rate case levels. See 5 TR 1176-1177. Staff’s proposal would also remove customer charge revenue (System Access Charges in Consumers Energy’s rates) from the amount which would be decoupled from sales. 5 TR 1178.

The Company believes Staff’s proposal would not accurately decouple the Company’s revenues from sales levels:

“The limitations proposed [by Staff, i.e. the Energy Optimization cap and the elimination of System Access revenues from the calculation] could severely reduce the amount of decoupled revenue that would be available to fund operations at MPSC approved cost levels for the benefit of customers. The utilization of a cap on decoupling revenue adjustments as proposed by Ms. Smith may, in many instances, result in adjustments that do not fully reflect the variations from rate case sales levels that are actually experienced. The failure to fully reflect these variations leaves the utility with a continuing disincentive to promote energy efficiency. In short, the imposition of a cap diminishes the effectiveness of the Revenue Decoupling Mechanism.” 3 TR 263-264.
Removing the proposed cap and reinserting revenue from the system access charge in the calculation of the target revenues would make Staff’s proposal acceptable. See 3 TR 264.

ABATE also criticizes the use of an RDM. According to ABATE’s witness, an RDM would “frustrat[e] the voluntary efforts of customers to reduce energy consumption”; “reduc[e] the Company’s motivation” to be “responsive” to customers’ needs; “creat[e] unnecessary rate volatility and uncertainty”; and potentially expose customers to “large rate surcharges.” 4 TR 806.

As Mr. Ruhl testified, the Company believes that these fears are unfounded:

“A. The Company does not agree that decoupling would impact the customer’s motivation to reduce their energy costs. The Company believes that its EO program is helping customers be aware of the energy savings that can be realized, which ultimately helps customers reduce energy costs and helps our business customers be more profitable.

Q. Does the Company agree that decoupling would impact the customer’s motivation to reduce their energy costs?

A. The Company does not agree that decoupling would impact the customer’s motivation to reduce their energy costs. The Company believes that its EO program is helping customers be aware of the energy savings that can be realized, which ultimately helps customers reduce energy costs and helps our business customers be more profitable.

Q. Does the Company feel that the RDM reduces Company motivation to be responsive to needs of its customers?

A. The Company does not feel the RDM reduces the Company’s motivation to be responsive to customers – in fact, just the opposite is true. If a proper decoupling mechanism is in place, the Company’s disincentive to helping customers reduce energy sales is removed. Thus the Company is free to concentrate on helping customers be more energy efficient without the negative impact of a reduction in collection of fixed costs, which are needed by the Company to maintain service quality, and continue to be responsive to our customers. In this way, decoupling aligns the interests of customers, shareholders and regulators.

Q. Does the Company feel that the RDM creates unnecessary rate volatility and uncertainty?
A. The Company disagrees that the RDM creates rate volatility and uncertainty. The Company is simply proposing to collect the non-fuel revenues that were already authorized by the Commission through the decoupling mechanism.

Q. Does the Company feel that the RDM exposes customers to potentially large rate surcharges?

A. No. Mr. Selecky’s statements that an RDM would expose customers to potentially large rate surcharges is not supported by any analyses or data. Rather, this is merely Mr. Selecky’s opinion.” 3 TR 265-266.

ABATE’s witness Mr. Selecky testified that, if the Commission were to adopt the Company’s proposed RDM, then certain modifications favored by ABATE should be included. These modifications are set forth at 4 TR 808 et seq. and include the exclusion of large industrial customers, a limitation of the RDM program to lost sales as a result of energy optimization programs, a sales trigger, a limitation to “volumetric” revenues, and excluding “nonvolumetric” revenues such as customer charges.

In his rebuttal testimony, Company witness Ruhl rebutted each of these assertions:

“Q. Mr. Selecky suggests that if the Company’s sales are higher in absolute terms than the level set in rates there should be no RDM surcharges. Does the Company agree with this position?

A. No. For example, this position fails to recognize that the Company’s largest customer has a deeply discounted rate that was approved by the Michigan Public Service Commission. An absolute increase in sales attributed solely to the growth of this single customer, would not provide the Company the funds necessary to maintain or improve quality service to its customers, and therefore should be rejected. A well-functioning decoupling mechanism will separate the collection of the Company’s fixed costs from the volumetric sales levels.

Q. Mr. Selecky recommends that non-volumetric charges, such as the customer charge be eliminated from the RDM calculations. Would you support this recommendation?
A. No. The system access charge revenue is non-fuel tariff revenue that should remain in the revenue totals for reasons previously stated in response to Staff on this same issue.

Q. Mr. Selecky states that it would be appropriate to exclude large industrial customers from the operation of the RDM, stating that there is no reason to include them in the RDM. Do you support this position?

A. No, with the exception of Rate E-1. A large number of industrial customers have shown a strong interest in our EO programs and associated rebates and for this reason I don’t feel they should be excluded from the RDM without valid reason. Rate E-1, on the other hand, has a fixed rate and is a large customer rate that should not be subject to the surcharge or credit. Should the Company’s RDM proposal be accepted, this should be reflected in the distribution of surcharges or credits.” 3 TR 267.

Intervenor Hemlock Semiconductor Corporation (“Hemlock”) also raised questions of responsiveness of the Company to customer needs and rate volatility. 6 TR 1255. Mr. Ruhl relied on his rebuttal testimony to ABATE in response to Hemlock. 3 TR 268.

Attorney General witness Coppola also recommended adjustments to the Company’s RDM proposal. See 4 TR 725-727. Company witness Ruhl addressed Mr. Coppola’s recommendations concerning a reconciliation methodology based on average customer usage and the use of weather-normalized sales in his rebuttal testimony at 3 TR 268.

As Mr. Ruhl testified, the Company’s RDM is an effort to move away from average customer usage, 3 TR 268, and is proposing to move away from that approach. Id. The Company is also “opposed to Mr. Coppola’s weather adjusted sales suggestion, for which no meaningful basis was provided.” Id.

Intervenor Kroger’s witness Mr. Townsend contends the Company’s RDM proposal would result in “single-issue ratemaking.” 3 TR 358. However, as Company witness Ruhl testified: “Revenue decoupling was contemplated and authorized by the Michigan
Legislature, and therefore it is an appropriate ratemaking mechanism to be considered by the Commission in this case.” 3 TR 269. Mr. Townsend also argues that customers that “self-direct” their energy efficiency programs should be exempt from the RDM. Mr. Ruhl testified that, since “[r]ates are established in a case to provide the utility with a stable and reasonable means of collecting its authorized revenue level,” excluding self-directing customers “creates inequality” among customers. Id.

Intervenor Energy Michigan’s witness Mr. Zakem proposes separate RDM adjustments be made for power supply and delivery and has asserted that the Company has allocated the revenue variance with regard to the fact that ROA customers do not take power supply from the Company. See, 6 TR 1225, 1228 et seq. Company witness Ruhl rebutted this testimony:

“The Company does not support EM’s proposal to create separate adjustments for power supply and delivery. The Company’s proposed RDM approach utilizes ROA distribution revenues as the numerator and total authorized revenue as the denominator in the derivation of the variance allocator for ROA customer group share of total revenue variance. The resultant percentage share for the ROA group, therefore, is smaller than it otherwise would be if derived using only total delivery revenue for the denominator. The Company believes that the application of the smaller variance allocator against the total variance to be allocated is an equitable approach, and indeed does recognize that ROA customers only take delivery service from the Company. Both the denominator of the variance allocator calculations and the allocated variance are composed of power supply and delivery revenues. Thus, the Company supports its allocation of revenue variance based on each rate schedule’s share of total authorized revenue as approved by the Commission in the most recent general rate case proceeding. Separate credits or charges for power supply and delivery are not necessary. In the event Staff’s method is adopted, Staff calculates the amount of decoupled revenue for ROA customers by using only distribution revenue, and this should address the concerns of EM.” 3 TR 270.
B. Uncollectible Expense Tracking Mechanism

1. Company’s Position

Company witness Kenneth C. Jones, Assistant Controller, testified concerning the volatility of the Company’s uncollectible expenses. 4 TR 963. Due to the uncertainty of LIHEAP funding, the economy in Michigan and other factors, the amount of uncollectible expense experienced by the Company has been extremely volatile. 4 TR 963.

This volatility can be seen in the initial projections of the Company’s 2011 uncollectible expense verses the actual amount of uncollectible expense. Without an adjustment for any LIHEAP funding reduction, at the time of filing the Company had projected an uncollectible expense of $19,770,000 for 2011. Exhibit A-23 (KCJ-2). In fact, the Company’s 2011 11-months actual uncollectible expense is $24,075,000, an amount larger than the 12-month 2011 projected number (either with or without a LIHEAP adjustment). 4 TR 979. When the projected electrical uncollectible expense for the month of December 2011 ($2.6 million) is added to the 2011 11-months actual uncollectible expenses it totals $26.6 million for fiscal year 2011. 4 TR 979-980. This extreme volatility weighs heavily in favor of an uncollectible expense tracking mechanism.

The Commission previously adopted UETM 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. 4 TR 960-961. The Company believes the Staff’s comments, as quoted by the Commission in Case No. U-15645 are on point with the circumstances currently faced by the Company.

“In its exceptions, the Staff continues to advocate for the UETM. The Staff states that, similar to Mich Con, Consumers is faced with an economic situation in Michigan that is beyond its control. The Staff further recommends that the UETM and the appropriate uncollectible expense level and methodology be reviewed and
adjusted annually.” November 2, 2009 Opinion and Order, Case No. U-15645, p. 56

The Company is well aware of the Staff’s current position against tracking mechanisms in general. However due to the economic situation in Michigan, the unusual circumstances faced by the Company, and the extreme volatility of the amount of uncollectibles, The Company respectfully requests the Commission reinstitute an uncollectible expense tracking mechanism.22

Staff witness Nwabueze and Attorney General witness Coppola rely on the passage of PA 286 as diminishing the need for trackers. However, as pointed out by Company witness Ronn J. Rasmussen:

“File and implement ratemaking doesn’t provide a remedy to changes from filing assumptions that happen early in a projected test year. Allowing for just 3 months between a rate order and the filing of the next general rate case could mean a lag of up to 15 months before new rates could be implemented to remedy an unforeseen, significant cost increase or decrease.” 3 TR 104.

If there is a significant cost decrease in uncollectible expenses, then customers would be overpaying until rates were adjusted. 3 TR 104. Conversely, if there is a significant cost increase in uncollectible expenses, then the Company would be under-collecting until rates were adjusted. 3 TR 105. A Commission order approving a tracking mechanism for uncollectible expenses would protect both customers and the Company from the volatile nature of uncollectible expenses. 3 TR 105.

22 The Michigan Court of Appeals has held that uncollectible expense tracking mechanisms are lawful. See: In re Application of Consumers Energy Co, 279 Mich App 180; 756 NW2d 253 (2008); In re Application of Michigan Consolidated Gas Co, 281 Mich App 545; 761 NW2d 482 (2008).
C. Electric Choice Sales Tracker Proposal

Company witness Ruhl testified concerning the potential for an electric choice sales tracker:

“A. . . . The Company is updating sales, which includes customer movement to Electric Choice, so it does not believe that an electric choice sales tracker is required at this time. However, the Company is proposing that in the event the Michigan Legislature increases the existing 10% cap on electric choice sales prior to the issuance of a final order in this case, the Commission reinstate the electric choice incentive mechanism (ECIM) as approved by the Commission in Case No. U-15645, with modifications to remove the 5% deadband and 10% incentive adjustment.

Q. Why does the Company believe the ECIM tracker would be necessary if the cap is increased?

A. An increase in the amount of ROA sales could represent a significant loss of revenue to the Company. For example, under current rates, an increase in the ROA load to 25% would result in losses of fixed revenue of approximately $300 million. As this would represent a significant change in sales that is impossible to predict, the Company believes that this tracker would be essential to maintain the financial health of the utility and maintain revenues needed for operations and investment in the utility.

Q. How would the ECIM work in conjunction with the RDM?

A. If the ECIM is approved, the Company proposes to remove the effect of the ROA changes from the decoupling reconciliation, so that the Company recovers the appropriate amount of revenues under each mechanism.” 3 TR 242-243.

D. Recovery of Clean Coal Plant Expenditures

Consumers Energy requests accounting and ratemaking authorization to amortize costs that were incurred by Consumers Energy in planning a super-critical pulverized coal generating plant (“the Clean Coal Plant”) to meet the needs of its customers. Consumers Energy
presented evidence these costs were prudently incurred and decisions to undertake planning activities, defer the coal plant, and then cancel the coal plant were reasonable. Consumers Energy is proposing the costs incurred be amortized over a 3-year period with the unamortized amount included in rate base.

1. **Clean Coal Plant Costs and Prudence**

The Company initially commenced planning for the construction of a clean coal plant in response to the 21st Century Energy Plan which was issued by then Governor Jennifer M. Granholm and Michigan Public Service Commission Chairman J. Peter Lark. 4 TR 966. The 21st Century Energy Plan recommended “…Michigan’s future energy needs be met through a combination of renewable resources and the cleanest generating technology, with significant energy savings achieved by increased energy efficiency.” 6 TR 1330. The recommendation continued, “…Michigan’s load growth is expected to grow an average of 1.2 percent per year over the next 20 years. Recognizing that the average age of Michigan’s power plants is 48 years, and that no Michigan utilities have undertaken baseload construction in almost 20 years, it is important that a new baseload plant can be built and financed while protecting customers from unnecessary costs. Modeling shows a need for a new baseload power plant no later than 2015, and since build time on a baseload plant is at least six years, the state should take action now.” 6 TR 1330.

In response to the 21st Century Energy Plan, the Company submitted an application for approval of a Balanced Energy Initiative (“BEI”). 6 TR 1331. One of the proposals within this application was for the construction of a new clean coal plant. 6 TR 1331. Due to a reduction in customer demand and a decline in natural gas prices along with other factors, the Company then deferred construction of the plant in 2010. 4 TR 966; 6 TR 1331.
The reduction in customer demand was due to economic conditions, resulting in excess generating capacity, and low spot market electric pricing. 6 TR 1332. Natural gas prices, due to the availability of shale gas, declined to a level that lowered the cost advantage of coal as compared to natural gas for use in electric generation. 6 TR 1332. In May 2010, Consumers Energy announced plans to defer planning of the coal plant. 6 TR 1333. On December 2, 2011, due to the continuance of these factors, the Company announced the cancellation of the Clean Coal Plant project. 4 TR 981, 6 TR 1338-1339.

Company witness David B. Kehoe, Director of Staff Electric Generation, testified concerning the expenses incurred during the planning of the proposed Clean Coal Plant. 6 TR 1327-1328. The expenses incurred are summarized on Exhibit A-31 (DBK-6) and consist of the following:

- Owners Engineer - $8.04 million, includes expenses paid to HDR/Cummins & Barnard, Inc. for project design, cost estimates, project schedule, risk analyses and permitting support.
- Permitting - $3.47 million, includes expenses paid to NTH Consultants, Ltd. for air quality services, including analyses, drafting and processing of the permit applications.
- Site Studies - $5.23 million, includes expenses paid to ACRO Service Corporation, Black & Veatch, Environmental Resources Management, Stone & Webster and URS Corporation Great Lakes for investigating over 100 potential building sites.
- Outside Legal - $1.69 million, includes expenses paid to Hunton & Williams and Miller, Canfield, Paddock & Stone for legal services and support of the air and wetlands permitting process.
- Certificate of Necessity (“CON”) - $560,000, includes expenses paid to ICF Resources, HIS Cera, Concentric Energy and Black & Veatch for services associated with obtaining a CON.
- Integrated Resource Planning (“IRP”) - $1.02 million, includes expenses for Cambridge Energy Research Association (“CERA”) membership and associated reports and studies.
- MISO - $77,000, includes expenses for application fees and system studies required to add additional capacity.
• Electric Power Research Institute (“EPRI”) - $859,000, includes expenses for EPRI membership and associated reports and studies.

• Carbon Capture & Sequestration (“CCS”) - $275,000, includes expenses paid to NTH Consultants, Ltd. to provide geologic well studies.

• Soil Testing - $186,000, includes expenses paid to STS Consultants Ltd. for site design and soil testing.

Mr. Kehoe presented evidence the expenses incurred for the planning of the new coal plant were reasonable and prudent. 6 TR 1328, 1333.23

2. Accounting for Clean Coal Plant Expenditures

Company witness Kenneth C. Jones, Assistant Controller, testified concerning the accounting for expenses for the clean coal plant. Mr. Jones calculated a proposed recovery of $21,750,721 of clean coal plant expenditures as amortization expense to be applied to all jurisdictional electric customers’ base rates over a 3-year period. 4 TR 965. This calculation includes a reduction for the land acquisition costs and a reduction for a MISO refund. 4 TR 966.

The Company requests the authority to create a regulatory asset (account 182.3) for the amount of the clean coal plant expenses, $21,750,721, and authority to then amortize this asset on a straight-line basis for a period of 36 months. 4 TR 966. The Company proposes the monthly amortization amount of $604,187 be included in all jurisdictional electric customers’ base rates. 4 TR 968. The accounting set forth by Mr. Jones at 4 TR 967 should be adopted by the Commission.

3. Ratemaking Recovery of Clean Coal Plant Expenditures

A ratemaking policy that allows timely recovery of prudently incurred planning costs will promote decisions that are in the best interest of customers and encourage utilities to undertake prudent planning activities without fear of negative ratemaking treatment. 3 TR 192.

23 The expenses were also part of the due diligence required for the future filing of a CON. 6 TR 1331.
As discussed above, record evidence establishes that: (i) decisions to initiate planning, defer construction, and ultimately cancel the Clean Coal Plant were all reasonable and prudent; and (ii) amounts Consumers Energy seeks to recover were reasonably and prudently incurred:

- At the time planning of the Clean Coal Plant was undertaken, the Governor, the MPSC Chairman, and the Company were all in agreement the energy produced by the Clean Coal Plant would be needed, that given the required lead time planning could not be delayed, and that planning for a Clean Coal Plant was reasonable;

- The incurred costs are reasonable and prudent costs and were reasonably incurred by Consumers Energy in planning for a Clean Coal Plant to meet the needs of its electric customers;

- The Clean Coal Plant expenses were incurred in response to Executive Directive 2006-2 and the 21st Century Energy Plan and the Capacity Needs Forum;

- The Clean Coal Plant expenses were made in the exercise of reasonable judgment;

- The Company’s May 2010 decision to defer development of the Clean Coal Plant was reasonable in light of changed conditions;

- The Company’s December 2011 decision that it was in the best interests of customers to cancel the Clean Coal Plant was reasonable as a result of changed conditions appearing likely to continue.


Erin Rolling, a Senior Rate Analyst in the Rates and Regulation Department, testified:

“Consumers Energy believes that a three-year amortization period reasonably balances Company and customers interests for these expenses. The majority of the expenditures were incurred during the three-year period prior to when the decision was made to defer development of the coal plant. Recovery in a timely manner of these expenses will help the Company attract capital for future expenditures and help it do so at a lower cost than if investors are concerned about recovery or timing of recovery of expenditures from customers. By spreading these costs over three years, the annual impact on a typical residential customer will be approximately $1.77 a year. This averages to approximately $0.15 per month. In addition, using a three-year amortization will more closely match customers paying the amortization expense with
customers at the time the expenses were incurred than might occur if a longer amortization period were used.” 3 TR 180.

The expenditures are shown by year on Exhibit MCAAA-5, Bates page 79401764. As shown on that page, while expenditures were incurred over five years, minimal expenses were incurred over two of those years,\(^{24}\) with 80% of the booked expenditures being incurred during 2007, 2008, and 2009. The decision to defer development of the Coal Plant was made in 2010. Given the period during which the majority of the expenses were incurred, the amortization dollar amount, and the impact on a typical residential customer, a 3-year amortization period is reasonable. Using a 3-year amortization period results in a jurisdictional test year Clean Coal Plant Amortization expense of $7.222 million. See Appendix C, page 1, line 5 and note 3.

Consumers Energy has proposed the unamortized Clean Coal Plant costs be included in rate base for the following reasons:

- Consumers Energy invested corporate capital in the Clean Coal Plant and should receive a return on those funds until they are recovered from customers;
- Rates established by the Commission in its orders in Consumers Energy rate Case No. U-15645 and Case No. U-16191 included booked Clean Coal Plant costs in rate base;
- In Case No. U-16191 the Commission excluded $14.7 million of \textit{projected} costs for the Clean Coal Plant in light of the decision to defer the plant, but did not remove the approximately $20 million of already incurred \textit{booked} Clean Coal Plant costs from rate base;
- Including the unamortized balance in rate base is consistent with current ratemaking;
- Including the unamortized balance in rate base helps assure that the Company and its investors are not harmed by prudently made decisions to defer and to ultimately cancel development of the Clean Coal Plant based upon changed conditions.

3 TR 181-182, 194-195. Exhibit A-7 (EAR-45), Schedule B2, line 9, includes the average total electric Clean Coal Plant amount of $18,126,000 in the development of the projected utility plant.

\(^{24}\) $651,000 of expenditures were booked in 2005 and $102,000 in 2011. Exhibit MCAAA-5, p. 79401764.
for the test year ending September 2012. The calculation of this test year average unamortized balance is shown on Exhibit A-7 (EAR-45), Schedule B2.

4. Responses to Staff, ABATE, and MCAA Witnesses

Witnesses for Staff, ABATE, and MCAA addressed various aspects of Consumers Energy’s Clean Coal Plant proposals in this case. For reasons set forth in this Brief and in the testimony and exhibits presented by Consumers Energy in this case, the Company’s proposals should be adopted and the proposals of other parties, to the extent inconsistent, rejected.

Staff witness Rusnak testified with respect to the Company’s request for recovery of Clean Coal Plant expenditures: “Until Consumers Energy fully commits to building or not building the plant, Staff does not believe it is appropriate to grant Consumers Energy recovery of the $21.75 million associated with the proposed Clean Coal Plant in this case.” 5 TR 1164. Similarly, Staff witness Birkam recommended recovery for the clean coal plant not occur “at this time” (i.e., until the plant is either abandoned or construction is resumed) stating this was supported by Ms. Rusnak. 5 TR 1036. At 5 TR 1077, Mr. Krause testified that in removing amounts attributable to the Clean Coal Plant, he was relying upon Mr. Birkam.

On December 2, 2011, the Company announced the cancellation of the Clean Coal Plant project. 4 TR 981, 6 TR 1338. The official cancellation of the project resolves the only objection to recovery raised by Staff witnesses in testimony. 6 TR 1338. As the plant has been cancelled, there is no reason to defer granting Consumers Energy’s request that the Commission authorize the creation of a regulatory asset as described previously and recovery in rates of incurred costs. The amount of the regulatory asset should be $21,750,721 to take into account a reduction for the land acquisition costs (the land will be used to facilitate operations at

25 The jurisdictional electric amount, shown on the same exhibit page, is $18,059,000.
the Karn/Weadock Generating Complex) and the MISO refund (a refund of the deposit made by the Company to MISO to perform system impact studies related to the new Clean Coal Plant). 4 TR 966, 982.

At 4 TR 813-814, ABATE witness Selecky identified four basic arguments in opposition to Consumers Energy’s proposals for recovery of Clean Coal Plant costs: (i) customers should not be required to pay for Clean Coal Plant costs because the plant did not go into service and is not used and useful in supply service; (ii) Consumers Energy was compensated for the risk in its rate of return; (iii) if amortization occurs it should be over five years with no return on the unamortized balance rather than three years with a return; and (iv) costs incurred after mid-year 2009 should be excluded. Mr. Selecky’s arguments should be rejected.

As discussed above, Consumers Energy incurred the Clean Coal Plant expenditures in order to serve its electric customers. Ms. Rolling testified:

“The costs incurred were resource planning costs. It would be difficult to evaluate and undertake necessary initial planning activities if planning costs were not incurred. The Company has presented evidence that these planning costs were reasonable based on information that was then available. For many years, Michigan has followed a well-established policy of allowing recovery from customers of prudently incurred planning and prudently incurred construction costs for power plants undertaken for the benefit of utility customers regardless of whether the plant ultimately is placed in service. With respect to the Clean Coal Plant, only preliminary planning costs are being sought in this case.” 3 TR 192.

Evidence shows the expenditures were reasonably incurred and that decisions to defer further expenditures, to initially maintain the option of proceeding with the Plant, and to ultimately cancel the plant were all reasonable. See e.g., 6 TR 1327-1334, 1338-1339. Mr. Selecky’s argument that recovery should be denied because the plant did not go into service should be
rejected. Mr. Selecky’s argument would tend to discourage utilities from engaging in prudent planning activities, to the detriment of customers.

Likewise, Mr. Selecky’s argument Consumers Energy was compensated for the risk in its rate of return should be rejected. As testified to by Ms. Rolling, given the circumstances and prior ratemaking, Consumers Energy and its investors had a reasonable expectation costs would be recovered if prudently incurred. 3 TR 193. Thus, denial of recovery of these prudent planning costs would be directly inconsistent with reasonable market/investor expectations. Mr. Selecky’s implicit contention that investors anticipated cost recovery disallowances has no logical or factual support.

Mr. Selecky did not identify why he concluded that amortization over five years was preferable to amortization over three years. Given that the majority of the expenditures were incurred over a 3-year period and in consideration of the amount of the amortization, three years reasonably balances goals of cost sharing and risk sharing. 3 TR 193-194. A return is appropriate for reasons discussed above.

Mr. Selecky also recommends that any expense incurred by the Company after mid-year 2009 should be disallowed. Using hindsight, Mr. Selecky claims that it is now known that excess generating capacity and low spot market electric prices have continued from mid-year 2009 up to the present. 6 TR 1353. Relying on hindsight, Mr. Selecky disagrees with any expense for the Clean Coal plant after mid-year 2009. 6 TR 1353. Mr. Selecky’s recommendation should not be adopted by the Commission as the Company had no way of knowing how long the economic downturn would last or when or how long a full economic recovery would take. 6 TR 1353-1354. Mr. Kehoe testified the Company prudently moved
forward with the new coal plant until it became apparent deferral was the most prudent action.\textsuperscript{26} 6 TR 1354. Given that the build time on a new plant is at least six years (6 TR 1330), it would not have been reasonable to defer construction in mid-year 2009.

MCAAA witness Peloquin testified that amortization should be over 10 years rather than three years and Consumers Energy should not be allowed a return on the unamortized balance. Mr. Peloquin argues a 10-year amortization is consistent with the Midland Plant amortization. However, in that instance, the Commission allowed recovery of \$760\ million and approved amortization of the previously unrecovered amount of approximately \$347\ million over 10 years. 3 TR 194. The annual amortization amount for the Midland Plant was larger than the entire Clean Coal Plant amortization that Consumers Energy seeks approval to amortize over three years. Given the amount, three years is more reasonable. Including the unamortized balance in rate base is appropriate for reasons discussed above.

E. **SG/AMI Accounting Clarification Request**

The Company has requested accounting clarification from the Commission concerning SG/AMI. 4 TR 968. It appears to the Company that certain SG/AMI “Guidelines” adopted in the November 4, 2010 order in Case No. U-16191 are inconsistent with existing provisions of the Uniform System of Accounts (“USofA”) and with prior guidelines included in MPSC order Case No. U-5281, AFUDC. 4 TR 968. The accounting inconsistencies are outlined in the testimony of Company witness Kenneth C. Jones, Assistant Controller. These inconsistencies are explained at 4 TR 968-972 of Mr. Jones’ testimony and are summarized as follows:

**Meters:** Guideline 5, found on page 16 of the November 4, 2010, order in Case No. U-16191 states:

\textsuperscript{26} The Company did defer construction of the plant May 2010. 6 TR 1333.
“5. Prior to the completion of the pilot, capitalized expenditures will be included in utility rate base as Construction Work in Progress (CWIP) with an Allowance for Funds Used during Construction (AFUDC) offset. Capitalized expenditures directly related to the pilot will not be reflected in rates until the pilot phase is concluded.” 4 TR 969.

Consumers’ interpretation of the USofA is that meters are to be included in Plant-in-Service and not held in CWIP, when meters are either in service or in inventory. 4 TR 969.

A. This account shall include the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve.” (Emphasis added). 4 TR 969.

**AFUDC:** The Company currently applies AFUDC to construction projects in accordance with the MPSC’s order in Case No. U-5281. 4 TR 970. This order requires a project to have an estimated cost of at least $50,000 with more than six months of on-site construction to qualify for AFUDC. 4 TR 970. Meters, communications equipment, and computer equipment do not meet the six month construction requirement, and therefore the Company does not apply AFUDC to these capital expenditures. 4 TR 970.

**Retirements:** The Company follows normal retirement and depreciation practices with respect to the retirement of electric mechanical meters being replaced by new SG/AMI meters. 4 TR 970. The accounting treatment is in compliance with the Electric USofA, Account 108, *Accumulated Provision for Depreciation of Electric Utility Plant (Major only)*, which states, in part:

“B. At the time of retirement of depreciable electric utility plant, this account shall be charged with the book cost of the property retired and the cost of removal and shall be credited with the salvage value and any other amounts recovered, such as insurance.” 4 TR 970-971.
Since the Company uses a remaining life technique when determining its depreciation rates, any un-depreciated cost would be collected through future depreciation rates when authorized by the Commission. 4 TR 971. The Company would also charge net salvage (salvage less cost of removal) to the depreciation reserve account, as required by the USofA, Account 108. 4 TR 971. The Company seeks confirmation that this is appropriate and consistent with the Staff Guidelines. 4 TR 971.

**Software:** Company policy is to capitalize software modification costs if the modification results in additional functionality, such as enabling software to perform tasks that it previously was incapable of performing. 4 TR 971. Capitalized software costs are closed to Plant-in-Service when the software is available for its intended use. 4 TR 971. This accounting is in compliance with Electric USofA, Account 107, *CWIP – Electric*, which states, in part:

“B. Work orders shall be cleared from this account as soon as practicable after completion of the job.” 4 TR 971.

There is a conflict between Electric USofA Account 107, which requires capitalized software costs to be closed to Plant-in-Service when available for its intended use, and with the Staff guidelines which states, in part:

“Capitalized expenditures directly related to the pilot will not be reflected in rates until the pilot phase is concluded.” 4 TR 972.

In summary, the Company thus seeks confirmation from the Commission that:

- Meters should continue to be closed to PLANT-IN-SERVICE when purchased,
- AFUDC should continue to be applied to projects in accordance with Case No. U-5281,
- USofA Account 107 should continue to be charged for retirement of electric mechanical meters, and
- Capitalized software modifications should continue to be closed to PLANT-IN-SERVICE when available for its intended used.
F. **Response Regarding MCAAA’s DOE Liability Issues**

MCAAA presented testimony addressing various issues involving spent nuclear fuel. These issues include Consumers Energy’s obligation under the federal Nuclear Waste Policy Act to make payments to the federal government for spent nuclear fuel generated prior to April 1983 and between April 1983 and when Consumers Energy sold its Palisades nuclear plant to Entergy Nuclear Palisades, LLC in April 2007. At page 23 of its June 10, 2008, order in MPSC Case No. U-15245 the Commission stated: “Consumers’ sale of Palisades allowed it to fully exit the risky nuclear generation industry.” (Emphasis added). The Pre-1983 DOE Liability is not included as a component of the projected test year rate base or in the capital structure. 3 TR 169, 170, 477-478. Indeed, there are no costs included in expenses sought by Consumers Energy or which will be incurred during the test year related to spent nuclear fuel or the DOE Liability. MCAAA’s efforts to interject such issues into this case should be rejected for reasons set forth in Consumers Energy’s Motion to Strike, filed in this docket on December 8, 2011, and as argued by Consumers Energy at 6 TR 1504-1515. If MCAAA chooses to pursue this issue in its initial Brief, Consumers Energy will respond to issues and argument raised by MCAAA in its Reply Brief.

G. **Response to NRDC/MEC’s Line Loss Issues**

Consumers Energy requests the Commission reject NRDC/MEC witness Sansoucy’s recommended disallowance of $18,786,000 in coal costs based on his criticism regarding the level of line losses on the Company’s system. This issue was previously dealt with by the Commission in Case No. U-16191 in which Mr. Sansoucy’s position was rejected by the Commission. November 4, 2010, order page 13, Case No. U-16191. The Company respectfully urges the Commission to reject Mr. Sansoucy’s recommendations again.
Mr. Sansoucy simplistically states a reduction in the Company’s line losses of 700,000,000 kWh would save ratepayers about $18,786,600 in coal costs. 4 TR 890. However, Mr. Sansoucy does not detail how the line losses should be eliminated or recognize the costs to eliminate the line losses. 4 TR 890.

The Company constructs its distribution system on an economic basis focusing on customer needs, the capacity of the system to serve, and the need to improve reliability. 4 TR 889. Line losses are taken into account, however due to economics they are not the primary driver for capital expenditures. 4 TR 889. It must also be remembered that regardless as to how the distribution system is constructed, not all line losses can be eliminated. 4 TR 889. “Line losses” is a general term equivalent to “total energy loss” and applies to all unaccounted for energy including such things as: transformer and power line losses due to current flow, fixed core losses associated with energized transformers, unmetered station power, and theft of power. 4 TR 890. Line losses also encompass similar unaccounted for energy losses on the Michigan Electric Transmission Company (“METC”) system. 4 TR 890.

In evaluating Mr. Sansoucy’s recommendation, the cost to install larger conductor and increase the voltage of the distribution system was calculated. 4 TR 892. As testified to by Mr. Anderson, the calculations prove that it does not make economic sense to reduce line losses by installing larger conductor or converting the distribution system to a higher voltage. 4 TR 891. According to Mr. Anderson’s calculations it would cost approximately $4.5 billion to convert all of Consumers Energy’s lower voltage distribution systems to 24.9 kV and approximately $4.4 billion to convert all of Consumers Energy’s existing No. 4 ACSR conductor to 1/0 ACSR conductor. 4 TR 892. However, even with the expenditure of this almost $10 billion, there would not be a complete elimination of line losses. 4 TR 892. As
Mr. Sansoucy even concedes, some amount of line losses is inevitable (even the higher voltage and larger conductors themselves experience some level of line losses). 4 TR 892; 6 TR 1498. Thus, Consumers Energy could spend almost $10 billion in an attempt to save a portion of the $18.8 million of line losses complained of by Mr. Sansoucy. Mr. Sansoucy’s recommendation does not make economic sense and should be rejected by the Commission.

H. **Response to the Attorney General’s Rate Case Expense Proposal**

Consumers Energy requests the Commission reject Attorney General witness Coppola’s recommendation to disallow $450,000 of O&M expenses related to rate case expenses and reject the recommendation the Company be required to maintain detailed records of time and expenses incurred during the preparation of a rate case. Consumers Energy, as a public utility, operates under the regulation of state and federal oversight. 3 TR 113. There are statutorily required reporting and filing requirements. The Company cannot just arbitrarily adjust utility rates or change the terms of service, but rather must file cases to seek Commission approval. The Company is involved in many types of filings before the Commission including electric and gas rate cases, energy optimization filings, renewable energy filings, gas cost recovery cases and power supply cost recovery cases. Most of these filings are required by state law. Mr. Coppola’s proposed disallowance should be rejected as the cost of these filings is a normal cost of doing business as a public utility.

Mr. Coppola’s suggestion that rate case costs have increased since the passage of PA 286 is incorrect. The Company has incurred little, if any, additional incremental expense related to the processing of rate cases since the passage of PA 286. 3 TR 113. In actuality, the Company’s overall non-union staff has been reduced by approximately 70 employees since passage of PA 286. Staff within the Rates Department, which has primary responsibility for the
coordination and processing of rate proceedings, has been reduced by half since 2003. 3 TR 113. Consumers Energy has become a more productive and streamlined organization which protects customers from unnecessary cost increases. 3 TR 113.

Mr. Coppola’s request to require the Company to maintain detailed records in order to monitor rate case expenses would be an undue administrative burden, not only for the Rates Department, but also for Company witnesses and their support staffs. 3 TR 113. This would not be an effective use of employee time or Company resources. 3 TR 113. The Company works very hard to keep O&M expenses low, and Mr. Coppola’s suggestion is counter-productive and should therefore be rejected.

VII. REVENUE DEFICIENCY CALCULATION

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 September 2012 test year of $180.935 million. The calculation of this deficiency is summarized in Appendix A.

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

A. Cost of Service

Company witness Eric Keaton presented the Company’s Cost-of-Service Study (“COSS”) by rate class. 3 TR 393 et seq. Mr. Keaton 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.” 3 TR 393-394.

Mr. Keaton’s test year analysis can be found at Exhibit A-5 (EJK-1) (Historical Year) and Exhibit A-11 (EJK-2), Schedule F-1, (Test Year–12 Months Ending September 2012). Mr. Keaton provides the rationale and the methodology for his COSS analysis in his direct testimony.

Two intervening parties, HSC and ABATE, suggested that the COSS methodology for allocating production costs should be changed from the 12CP method demand allocator used by Mr. Keaton to a 4CP method. Mr. Keaton indicated “the Company does support using the 4CP as the demand component of the production capacity allocator.” 3 TR 404. These two intervenors also suggested the Company’s transmission costs should be allocated using a 12CP methodology with no energy weighting. 3 TR 405-406. Mr. Keaton agreed with these recommendations. Id. Mr. Keaton also agreed with Staff’s recommendation that income tax related items should be functionalized on a pretax net operating income basis. 4 TR 406. Mr. Keaton also agreed with Staff that Critical Peak Summer Purchased Power should be allocated on allocation factor 107 instead of factor 106. Id.

B. Rate Design and Tariff Issues

Company witness Ruhl also provided the Company’s position concerning rate design and certain changes to the Company’s tariffs. As Mr. Ruhl testified, the goal of the rate design provided by the Company in this case was to “phase in cost-based rates under certain constraints by October 15, 2013.” 3 TR 226. The Company is proposing to meet this requirement by “continuing the phasing-out of residential subsidies and other subsidies” in this case. Id. The Company proposes to reduce the current residential subsidy of $69 million by approximately $39 million, leaving a residential subsidy of approximately $30 million. This
remaining subsidy would be addressed either by filing a rate case in 2012 that removes the subsidy completely or in the absence of a rate case filing, by filing new tariff sheets that reflect a final phase out of the $30 million. 3 TR 227. Other rates, including the Senior Citizen discount, the Income Assistance Provisions, the Economic Development Rate (E-1), the General Economic Development (“GED”) Provision, the General Service Furnace/Metal Melting Provision (“GFM”) and the Municipal Pumping Service Provision (“GMP”) are also being phased out. 3 TR 227-228.

Mr. Ruhl outlined the proposals for rate design changes supported by the Company. These include the following: Roll in of PSCR costs into base rates; changes to the Residential Rate Design increasing the monthly fixed residential system access charge by $1 per month (toward cost-based costs); and Non-residential rate design adjustments including reductions to the credits provided under the GMP and GFM rates. In response to a Commission directive from Case No. U-16191, the Company is proposing a Metal Melting Primary Pilot Rate. The Company is also proposing voltage level price differentiation for the energy and distribution delivery charges for Rate GP as well as for the distribution delivery charges of Rate GPD. Mr. Ruhl discusses these proposals at 3 TR 230 et seq.

With respect to tariff changes, Mr. Ruhl has listed proposed tariff changes on Exhibit A-40 (BMR-7). That exhibit contains a listing of the proposed tariff changes together with a brief summary of the changes.

Various intervenors took issue with certain of Mr. Ruhl’s positions relating to rate design and tariff changes.

1. **Design of Rate GPD**

   ABATE’s witness, Mr. Selecky, asserted that the GPD rate is not set at cost. See, 4 TR 790 et seq. Mr. Selecky’s argument, however, does not account for the fact that “within the
GPD schedule the delivery rates by voltage level do deviate from the amounts shown in the Company’s cost study.” 3 TR 248 (Rebuttal Testimony of Company witness Ruhl). This deviation was done after taking into account the need to “maintain price signals and [to] mitigate rate shock.” *Id.* The GPD schedule is composed of the 3 voltage levels, CVL 1, CVL 2 and CVL 3. Taking all 3 of these subparts into account:

“CVL 1 and CVL 2 customers would pay $6.6 million and $2.5 million below the corresponding amounts in the cost study, respectively. This shortfall is absorbed by the CVL 3 customers so that collectively the voltage levels recover the cost-to-serve GPD.” 3 TR 249.

Mr. Ruhl recognizes that the varying rates for voltage levels deviate from the cost study:

“Q. What is your recommendation concerning the voltage level rate design raised by Mr. Selecky?

A. In its rate design the Company considered voltage level implications along with the impact on price signals and rate shock. As such I recommend the Commission adopt the rate design set forth in my direct testimony. However, I recommend the Commission expand its scope to also include power supply costs should they agree with Mr. Selecky’s conclusion that delivery rates move toward their cost-to-serve by voltage level. That is, if having cost based delivery rates by voltage is desireable, then by the same logic it holds that cost based power supply rates are also desireable.” 3 TR 249.

Kroger witness Townsend, also criticizes the Company’s Rate GPD rate design. Mr. Townsend is concerned that the distribution energy component of that rate has increased while the other two components (the demand charge and the system access charge) have decreased. See, 3 TR 350 *et seq.* However, Mr. Ruhl has explained the reason why this rate component has increased and has explained the regulatory theory supporting that rate component. 3 TR 250-251. As Mr. Ruhl testified, “[t]he rate design that has been proposed balances these rate schedules and voltage levels to produce the most equitable solution for the
customers.” 3 TR 250. Mr. Townsend has focused solely on one component of the Rate GPD (i.e., the distribution energy component) but Rate GPD should be analyzed in its entirety. The Company’s obligation, as explained by Mr. Ruhl, is to “design rates to send the correct price signals and recover the costs associated with that customer class,” 3 TR 250-251, and that obligation includes weighing the costs to serve and mechanisms for recovery “over the entirety of the GP and GPD rate schedules.” 3 TR 251.

2. **Base PSCR Costs**

MCAAA’s witness advocates using the most recent historical PSCR costs as the amount to include in this case rather than the projected PSCR expenses for the test period. Such a methodology would be inconsistent with the cost and revenue projections used to develop the Company’s rates in the test period. This proposal should be rejected.

3. **Rate GSG-2**

Kroger and Hemlock propose certain changes to the Company’s proposed Rate GSG-2. The first proposed change is a modification to the tariff to avoid purported duplicative billing of delivery costs. However, as Mr. Ruhl testified, “there simply isn’t any duplicative billing.” 3 TR 253. Neither witness provides an alternative that would presumably perform this billing task better. Mr. Ruhl provides an example in his rebuttal testimony, see, 3 TR 253-254.

Hemlock also proposes a credit for substation ownership in Rate GSG-2. First, it should be noted that a credit for substation ownership is already included in the Company’s tariffs. 3 TR 254-255. However, as Mr. Ruhl explains at 3 TR 254-255, the Company’s proposal is carefully designed to recover the costs related to serving the customers that qualify for service under this rate. Additional credits would prevent recovery of distribution costs, including skewing and the allocated portion of Commission-approved discounts. See, 3 TR 254.
A further substation credit would violate fundamental regulatory cost-recovery principles. Hemlock also expresses a concern that ROA customers are being required to take standby power from Consumers Energy. However, as Mr. Ruhl testified, the Company is not proposing to provide standby power to ROA customers, having been relieved of that obligation by 2000 PA 141. See MCL460.10b(4); 3 TR 255. The proposed language to be added to the GSG-2 tariff by the Company, see, Exhibit A-40 (BMR-7), page 1, is intended to “ensure the Company properly collects revenue for delivery service provided to customers electing to install generation in order to self-supply.” 3 TR 255-256.

4. **Power Factor Adjustment**

Hemlock also proposes to alter the Company’s power factor adjustment by introducing a sliding scale for power factors above .9. The Company’s tariff, however, is intended to incentivize customers to maintain as efficient a power factor as possible. 3 TR 256-257. “Low power factor loads lead to increased costs in serving customers as electrical distribution system efficiencies are diminished, resulting in corrective action necessarily taken by the utility.” 3 TR 256. Hemlock’s witness has not provided any persuasive reason why his “sliding scale” approach to the power factor credit is more effective than what has been used for many years. Further, “incremental increases in the power factor above 95% exhibit diminishing returns as they approach unity [i.e., 100%].” 3 TR 257 (testimony of Company witness Ruhl). Mr. Gorman has also removed – without any apparent justification – the substation ownership credit provision reference from the power factor tariff section. See, 6 TR 1270. This revision alters a delicately balanced recovery mechanism that has been previously approved by the Commission without any reasoned analysis.
5. **Skewing and Discount Allocations**

With respect to skewing and discount allocations, the MPSC Staff proposes to continue using electric sales as the basis for allocating skewing and discounts. The Company disagrees with this proposal:

“A...With an emphasis on encouraging business growth in the state, the Company believes that using the cost-to-serve to allocate skewing and discounts is more equitable. It’s true that residential customers will pay more by using the cost-to-serve to allocate the skewing and discounts. However, by spreading it over a much larger customer base the impact to any particular residential customer is minimal.

Q. Please continue.

A. For example, assume that changing the skewing and discount allocation method from electric sales to the cost-to-serve shifts $10 million annually from the large business classes to the residential class and that the residential and large business classes are composed of 1.5 million and 5,000 customers, respectively. From this example the impact to a residential customer is approximately $0.56/month ($10,000,000/12*1,500,000). On the other hand, the savings to a business customer is much more substantial at $167,000/month (-$10,000,000/12*5,000). By reducing the skewing and discount burden on business customers it frees capital that can be reinvested into expanding their operations in Michigan.” 3 TR 258-259.

ABATE’s arguments concerning skewing with GPD to the various voltage levels using an average of demand and electric sales is not explained. See 3 TR 259. The Commission should reject this proposal.

6. **System Access Charge**

Staff witness Pung recommends leaving the residential system access charge undisturbed at $6.00 per month. However, as Mr. Ruhl notes, the cost-of-service study undertaken for this case demonstrates that the system access charge should be raised to “at least $7.00/month.” 3 TR 259.
7. **Proposed Separate Municipal Rate Design**

The municipal intervenors propose a separate pumping rate from other commercial and industrial classes. This proposal “will likely be greater based on the usage characteristics.” 3 TR 260. The municipal pumping credits “will be phased-out to comply with the law and rates for municipal pumping customers must reflect cost-to-serve.” 3 TR 260.

8. **Changes to Metal Melting Pilot Program**

ABATE proposes to alter the Company’s proposed Metal Melting Pilot program by permitting customers to participate in an interruptible service. However, the Company believes that in order to gain information concerning these customers and their usage patterns, it would be preferable that the Company’s proposal be approved as proposed. See also, 3 TR 261.

IX. **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 amount of $180.935 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: January 24, 2012

By:

Jon R. Robinson (P27953)
H. Richard Chambers (P34139)
John C. Shea (P36854)
Raymond E. McQuillan (P24100)
Eric V. Luoma (P42678)
One Energy Plaza
Jackson, Michigan 49201
Attorneys for Consumers Energy Company
(517) 788-0980
## Jurisdictional Basis

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>CECo Initial Position (a)</th>
<th>MPSC Staff asFiled Position (b)</th>
<th>CECo Initial Brief Presentation (c)</th>
<th>Variance ((c) less (d))</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Rate Base</td>
<td>$7,538,872</td>
<td>$7,309,995</td>
<td>$7,653,801</td>
<td>($343,806)</td>
</tr>
<tr>
<td>2</td>
<td>Rate of Return</td>
<td>6.92%</td>
<td>6.55%</td>
<td>6.86%</td>
<td>-0.31%</td>
</tr>
<tr>
<td>3</td>
<td>Income Required</td>
<td>$521,595</td>
<td>$478,751</td>
<td>$524,821</td>
<td>($46,071)</td>
</tr>
<tr>
<td>4</td>
<td>Adjusted Net Operating Income</td>
<td>402,160</td>
<td>455,049</td>
<td>414,272</td>
<td>$40,777</td>
</tr>
<tr>
<td>5</td>
<td>Income Deficiency</td>
<td>$119,435</td>
<td>$23,702</td>
<td>$110,549</td>
<td>($86,847)</td>
</tr>
<tr>
<td>6</td>
<td>Revenue Multiplier</td>
<td>1.6367</td>
<td>1.6367</td>
<td>1.6367</td>
<td>-</td>
</tr>
<tr>
<td>7</td>
<td>Revenue Deficiency (Sufficiency)</td>
<td>$195,475</td>
<td>$38,792</td>
<td>$180,935</td>
<td>($142,143)</td>
</tr>
</tbody>
</table>

**Footnotes:**

1. CECo Initial Brief, Appendix B.
2. Ex. A-9 (DVR-1), Schedule D1
3. CECo Initial Brief, Appendix C.
4. Ex. A-8 (EAR-49), Schedule C2
5. Ex. S-4 (KB), Schedule D1
6. CECo Initial Brief, Appendix E, page 1 of 2
## Comparison of the September 2012 Test Year Rate Base for CECo Positions and the MPSC Staff Position (000)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>CECo Initial Position</th>
<th>MPSC Staff Initial as-Filed Position</th>
<th>CECo Initial Brief Presentation</th>
<th>Variance (c) less (d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Utility Plant in Service</td>
<td>(a) $10,174,282</td>
<td>(b) $10,175,271</td>
<td>(c) $10,175,271</td>
<td>$-</td>
</tr>
<tr>
<td>2</td>
<td>Plant in Service</td>
<td>(b) $2,956</td>
<td>(c) $4,733</td>
<td>(d) $4,733</td>
<td>$-</td>
</tr>
<tr>
<td>3</td>
<td>Plant Held for Future Use</td>
<td>(a) $749,893</td>
<td>(b) $539,610</td>
<td>(c) $696,470 ($156,860)</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Construction Work in Progress</td>
<td>(a) $18,059</td>
<td>(b) -</td>
<td>(c) $18,059</td>
<td>(d) $18,059</td>
</tr>
<tr>
<td>5</td>
<td>Clean Coal Plant</td>
<td>(a) $10,945,190</td>
<td>(b) $10,719,614</td>
<td>(c) $10,894,533</td>
<td>(d) $174,919</td>
</tr>
<tr>
<td>6</td>
<td>Total Utility Plant</td>
<td>(b) $6,977,170</td>
<td>(c) $6,748,905</td>
<td>(d) $6,923,824</td>
<td>(c) $174,919</td>
</tr>
<tr>
<td>7</td>
<td>Less: Accum. Depreciation and Amortization</td>
<td>(a) $42,003</td>
<td>(b) $42,003</td>
<td>(c) $42,003</td>
<td>(d) $-</td>
</tr>
<tr>
<td>8</td>
<td>Net Utility Plant</td>
<td>(a) $603,705</td>
<td>(b) $603,094</td>
<td>(c) $771,980 ($168,886)</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Retainers &amp; Customer Advances</td>
<td>(a) $5,645</td>
<td>(b) $11,161</td>
<td>(c) $125,615</td>
<td>(d) $306,906</td>
</tr>
<tr>
<td>10</td>
<td>Working Capital</td>
<td>(a) $306,906</td>
<td>(b) $306,094</td>
<td>(c) $771,980 ($168,886)</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Total Rate Base</td>
<td>(a) $7,538,872</td>
<td>(b) $7,309,995</td>
<td>(c) $7,653,801 ($343,805)</td>
<td></td>
</tr>
</tbody>
</table>

### Footnotes:
1. Ex. A-7 (EAR-43), Schedule B1, Development of Rate Base
2. Ex. S-2 (KSK), Schedule B1, Rate Base
3. Ex. S-2 (KSK), Schedule B2, Utility Plant, Column e, Line 7
4. Add: Test Year September 2012 Capital Expenditures
   - J. Rusnak Direct Testimony, Page 6, Lines 15 - 18
     - B.C. Cobb $5,645
     - J.R. Whiting 11,161
   - J. Rusnak Direct Testimony, Page 11, Lines 3 - 9
     - PM 2.5 $125,615
     - Mercury 158,657
     - 316b 1,918
     - RCRA & Other 3,910
   - Subtotal $306,906
   - C. Reasoner Direct Testimony, Page 14, Lines 3 - 12
     - Reliability 9,333
   - Total $316,239
   - Average Test Year Sept. 2012 Capital Exp. (Total Divided by 2) $158,120
     - 700,696
   - Jurisdictional Factor 0.99397
   - Revised September 2012 Test Year Jurisdictional CWIP $696,470
4. EARolling Revised Rebuttal Testimony, page 5, line 4
### Jurisdictional Basis

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>CECo Initial Position</th>
<th>MPSC Staff as-Filed Position</th>
<th>CECo Initial Brief Position</th>
<th>Variance (c) less (d)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
<td>(e)</td>
</tr>
<tr>
<td>1</td>
<td>Total Revenues</td>
<td>$3,725,530</td>
<td>$3,725,535</td>
<td>$3,725,535</td>
<td>$0</td>
</tr>
<tr>
<td>2</td>
<td>Fuel Used and P&amp;I Expense</td>
<td>$1,987,675</td>
<td>$1,987,686</td>
<td>$1,987,686</td>
<td>$0</td>
</tr>
<tr>
<td>3</td>
<td>Other O&amp;M</td>
<td>653,267</td>
<td>612,611</td>
<td>650,206</td>
<td>(1,405)</td>
</tr>
<tr>
<td>4</td>
<td>Depreciation and Amortization Expense</td>
<td>361,702</td>
<td>333,695</td>
<td>354,595</td>
<td>(20,900)</td>
</tr>
<tr>
<td>5</td>
<td>Clean Coal Plant Amortization Expense</td>
<td>7,222</td>
<td>-</td>
<td>7,222</td>
<td>(0)</td>
</tr>
<tr>
<td>6</td>
<td>R&amp;PP Tax</td>
<td>135,735</td>
<td>134,498</td>
<td>135,735</td>
<td>(1,237)</td>
</tr>
<tr>
<td>7</td>
<td>Other General Taxes</td>
<td>25,937</td>
<td>25,977</td>
<td>25,937</td>
<td>0</td>
</tr>
<tr>
<td>8</td>
<td>Local and State Income Taxes</td>
<td>31,610</td>
<td>35,856</td>
<td>31,841</td>
<td>40</td>
</tr>
<tr>
<td>9</td>
<td>Federal Income Tax</td>
<td>122,253</td>
<td>142,085</td>
<td>120,070</td>
<td>22,015</td>
</tr>
<tr>
<td></td>
<td>Total Expenses</td>
<td>$3,325,400</td>
<td>$3,272,408</td>
<td>$3,313,293</td>
<td>($40,885)</td>
</tr>
<tr>
<td>11</td>
<td>Net Operating Income</td>
<td>$400,130</td>
<td>$453,127</td>
<td>$412,242</td>
<td>$40,885</td>
</tr>
<tr>
<td>12</td>
<td>Add: AFUDC</td>
<td>2,030</td>
<td>1,922</td>
<td>2,030</td>
<td>(108)</td>
</tr>
<tr>
<td>13</td>
<td>Adjusted Net Operating Income</td>
<td>$402,160</td>
<td>$455,049</td>
<td>$414,272</td>
<td>$40,777</td>
</tr>
</tbody>
</table>

**Footnotes:**

1. Exhibit A-8 (EAR-48), Schedule C1, Column c, Lines 4 - 6 and Lines 8 - 19
2. Exhibit A-8 (EAR-48), Schedule C1, Column c, Line 7 less Jurisdictional Clean Coal Plant Amortization
3. Exhibit A-8 (EAR-52), Schedule C6, Line 16 $7,250
4. Jurisdictional Factor 0.996074
5. Jurisdictional Clean Coal Plant Amortization $7,222
6. CECo Initial Brief, Appendix C, Page 2 of 2
7. CECo Initial Brief, Appendix D
8. Exhibit A-8 (EAR-53a), Schedule C6a, Line 38 less Jurisdictional Clean Coal Plant Amortization
9. Column C, Line 7 plus the sum of Column E, lines 2 - 6 multiplied by 6%
10. Column C, Line 8 plus the sum of Column E, lines 2 - 7 multiplied by 35%
### Calculation of MPSC Staff Jurisdictional NOI (000) Page 2 of 2

<table>
<thead>
<tr>
<th>Line No.</th>
<th>MPSC Staff</th>
<th>Jurisdictional</th>
<th>Jurisdictional NOI (000)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Description</td>
<td>Position (^1)</td>
<td>Factors (^2)</td>
</tr>
<tr>
<td>(a)</td>
<td>(b)</td>
<td>(c) ((\text{d}) / (\text{b}))</td>
<td>(d)</td>
</tr>
<tr>
<td>1</td>
<td>Total Revenues</td>
<td>$ 3,747,275</td>
<td>0.994198</td>
</tr>
<tr>
<td>2</td>
<td>Fuel Used and P&amp;I Expense</td>
<td>$ 2,007,195</td>
<td>0.990280</td>
</tr>
<tr>
<td>3</td>
<td>Other O&amp;M</td>
<td>614,929</td>
<td>0.996230</td>
</tr>
<tr>
<td>4</td>
<td>Depreciation Expense</td>
<td>334,869</td>
<td>0.996494</td>
</tr>
<tr>
<td>5</td>
<td>R&amp;PP Tax</td>
<td>134,842 (^2)</td>
<td>0.997450</td>
</tr>
<tr>
<td>6</td>
<td>Other General Taxes</td>
<td>26,043 (^2)</td>
<td>0.997450</td>
</tr>
<tr>
<td>7</td>
<td>Local and State Income Taxes</td>
<td>35,948 (^3)</td>
<td>0.997450</td>
</tr>
<tr>
<td>8</td>
<td>Federal Income Tax</td>
<td>141,664</td>
<td>1.002972</td>
</tr>
<tr>
<td>9</td>
<td>Total Expenses</td>
<td>$ 3,295,492</td>
<td>1.002972</td>
</tr>
<tr>
<td>10</td>
<td>Net Operating Income</td>
<td>$ 451,784</td>
<td>1.002972</td>
</tr>
<tr>
<td>11</td>
<td>Add: AFUDC</td>
<td>1,933</td>
<td>0.994309</td>
</tr>
<tr>
<td>12</td>
<td>Adjusted Net Operating Income</td>
<td>$ 453,717</td>
<td>0.994309</td>
</tr>
</tbody>
</table>

**Footnotes:**

1. Ex. S-3 (BAW), Schedule C1
2. Ex. S-4 (YCT), Schedule C7
3. Ex. S-4 (YCT), Schedule C9 plus Ex. S-4 (YCT), Schedule C10
4. Ex. S-6 (CEP), Schedule F1, page 1 and supporting Cost of Service Study
5. Ties to Ex. S-6 (CEP), Schedule F1, page 1, line 15(b)
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>CECo Initial Position</th>
<th>MPSC Staff asFiled Position</th>
<th>CECo Initial Brief Presentation</th>
<th>Variance (c) less (d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Electric Distribution</td>
<td>$166,961</td>
<td>$166,961</td>
<td>$166,961</td>
<td>$-</td>
</tr>
<tr>
<td>2</td>
<td>Forestry</td>
<td>53,000</td>
<td>41,083</td>
<td>53,000</td>
<td>(11,917)</td>
</tr>
<tr>
<td>3</td>
<td>LIEEF (Vulnerable Household Warmth Fund)</td>
<td>26,536</td>
<td>26,536</td>
<td>26,536</td>
<td>-</td>
</tr>
<tr>
<td>4</td>
<td>Fossil &amp; Hydro Generation</td>
<td>176,366</td>
<td>164,836</td>
<td>176,366</td>
<td>(11,530)</td>
</tr>
<tr>
<td>5</td>
<td>Electric Supply</td>
<td>9,984</td>
<td>9,984</td>
<td>9,984</td>
<td>-</td>
</tr>
<tr>
<td>6</td>
<td>Business Technology Solutions</td>
<td>32,834</td>
<td>32,170</td>
<td>32,834</td>
<td>(664)</td>
</tr>
<tr>
<td>7</td>
<td>Smart Grid Program</td>
<td>7,072</td>
<td>7,072</td>
<td>4,000</td>
<td>3,072</td>
</tr>
<tr>
<td>8</td>
<td>Pension Plan</td>
<td>40,638</td>
<td>40,638</td>
<td>40,638</td>
<td>-</td>
</tr>
<tr>
<td>9</td>
<td>Defined Company Contribution Plan</td>
<td>3,931</td>
<td>3,931</td>
<td>3,931</td>
<td>-</td>
</tr>
<tr>
<td>10</td>
<td>401(k) Savings Plan</td>
<td>6,721</td>
<td>6,721</td>
<td>6,721</td>
<td>-</td>
</tr>
<tr>
<td>11</td>
<td>Active Health Care/LTD</td>
<td>30,451</td>
<td>30,451</td>
<td>30,451</td>
<td>-</td>
</tr>
<tr>
<td>12</td>
<td>Retiree Health Care &amp; Life Insurance</td>
<td>25,250</td>
<td>25,250</td>
<td>25,250</td>
<td>-</td>
</tr>
<tr>
<td>13</td>
<td>Corporate</td>
<td>30,085</td>
<td>28,080</td>
<td>30,085</td>
<td>(2,005)</td>
</tr>
<tr>
<td>14</td>
<td>Uncollectibles</td>
<td>32,346</td>
<td>18,804</td>
<td>32,346</td>
<td>(13,542)</td>
</tr>
<tr>
<td>15</td>
<td>Injuries &amp; Damages</td>
<td>4,985</td>
<td>3,880</td>
<td>4,985</td>
<td>(1,105)</td>
</tr>
<tr>
<td>16</td>
<td>Accounts Receivable Sales Costs</td>
<td>1,082</td>
<td>1,082</td>
<td>1,082</td>
<td>-</td>
</tr>
<tr>
<td>17</td>
<td>Jobwork Expense</td>
<td>7,661</td>
<td>7,661</td>
<td>7,661</td>
<td>-</td>
</tr>
<tr>
<td>18</td>
<td>Interest Income on Cash Equivalents</td>
<td>(212)</td>
<td>(212)</td>
<td>(212)</td>
<td>-</td>
</tr>
<tr>
<td>19</td>
<td>Test Year Other O&amp;M</td>
<td>$655,691</td>
<td>$614,929</td>
<td>$652,619</td>
<td>$(37,691)</td>
</tr>
<tr>
<td>20</td>
<td>Jurisdictional Factor</td>
<td>0.996304</td>
<td>0.996230</td>
<td>0.996304</td>
<td>-</td>
</tr>
<tr>
<td>21</td>
<td>Test Year Jurisdictional Other O&amp;M</td>
<td>$653,267</td>
<td>$612,611</td>
<td>$650,206</td>
<td>$(37,595)</td>
</tr>
</tbody>
</table>

Footnotes:
1. Ex. A-8 (EAR-52), Schedule C5
2. Ex. S-3 (BAW), Schedule C5
3. Ex. A-8 (EAR-52), Schedule C5, Lines 1 - 6 and Lines 8 - 18
4. Ex. S-17 (Staff), Page 4 of 11
5. Ex. S-6, Schedule F1 - Column (b) Line 8 divided by Column (a) Line 8.
<table>
<thead>
<tr>
<th>Line</th>
<th>Description</th>
<th>Amount Outstanding</th>
<th>% of Pre-tax</th>
<th>% of Total Capital</th>
<th>Cost Rate</th>
<th>Permanent Capital Cost %</th>
<th>Total Cost %</th>
<th>Conversion Factor</th>
<th>Pre-tax Weighted Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Long-Term Debt</td>
<td>4,134,000</td>
<td>48.11%</td>
<td>39.39%</td>
<td>5.70%</td>
<td>2.74%</td>
<td>2.24%</td>
<td>1.0000</td>
<td>2.24%</td>
</tr>
<tr>
<td>2</td>
<td>Preferred Stock</td>
<td>44,000</td>
<td>0.51%</td>
<td>0.42%</td>
<td>4.46%</td>
<td>0.02%</td>
<td>0.02%</td>
<td>1.6367</td>
<td>0.03%</td>
</tr>
<tr>
<td>3</td>
<td>Common Equity</td>
<td>4,415,000</td>
<td>51.38%</td>
<td>42.07%</td>
<td>10.70%</td>
<td>5.50%</td>
<td>4.50%</td>
<td>1.6367</td>
<td>7.37%</td>
</tr>
<tr>
<td>4</td>
<td>Total Permanent Capital</td>
<td>8,593,000</td>
<td>100.00%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Short Term Debt</td>
<td>184,000</td>
<td>1.75%</td>
<td></td>
<td>3.52%</td>
<td></td>
<td></td>
<td></td>
<td>0.06%</td>
</tr>
<tr>
<td>6</td>
<td>Deferred Income Taxes</td>
<td>1,667,000</td>
<td>15.89%</td>
<td></td>
<td>0.00%</td>
<td></td>
<td></td>
<td></td>
<td>1.0000</td>
</tr>
<tr>
<td>7</td>
<td>Deferred Income Taxes - MBT</td>
<td>-</td>
<td>0.00%</td>
<td></td>
<td>0.00%</td>
<td></td>
<td></td>
<td></td>
<td>1.0000</td>
</tr>
</tbody>
</table>

**Job Develop, Investment Tax Credit**

<table>
<thead>
<tr>
<th>Line</th>
<th>Description</th>
<th>Amount Outstanding</th>
<th>% of Pre-tax</th>
<th>% of Total Capital</th>
<th>Cost Rate</th>
<th>Permanent Capital Cost %</th>
<th>Total Cost %</th>
<th>Conversion Factor</th>
<th>Pre-tax Weighted Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>Long-term Debt</td>
<td>25,000</td>
<td>0.24%</td>
<td></td>
<td>5.70%</td>
<td></td>
<td></td>
<td></td>
<td>0.01%</td>
</tr>
<tr>
<td>9</td>
<td>Preferred</td>
<td>-</td>
<td>0.00%</td>
<td></td>
<td>4.46%</td>
<td></td>
<td></td>
<td></td>
<td>1.6367</td>
</tr>
<tr>
<td>10</td>
<td>Common Equity</td>
<td>25,000</td>
<td>0.24%</td>
<td></td>
<td>10.70%</td>
<td></td>
<td></td>
<td></td>
<td>1.6367</td>
</tr>
<tr>
<td>11</td>
<td>Total Capitalization</td>
<td>10,494,000</td>
<td>100.00%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>6.86%</td>
<td>9.76%</td>
</tr>
</tbody>
</table>

Source: Ex. A-60 (DVR-12)
<table>
<thead>
<tr>
<th>Line</th>
<th>Description</th>
<th>Amount Outstanding</th>
<th>% of Pre-tax</th>
<th>% of Cost Permanent</th>
<th>Cost Rate</th>
<th>Permanent Capital Cost</th>
<th>Total Cost</th>
<th>Conversion Factor</th>
<th>Pre-tax Weighted Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Long-Term Debt</td>
<td>$4,134,000</td>
<td>48.11%</td>
<td>39.39%</td>
<td>5.70%</td>
<td>2.74%</td>
<td>2.24%</td>
<td>1.0000</td>
<td>2.24%</td>
</tr>
<tr>
<td>2</td>
<td>Preferred Stock</td>
<td>44,000</td>
<td>0.51%</td>
<td>0.42%</td>
<td>4.46%</td>
<td>0.02%</td>
<td>0.02%</td>
<td>1.6367</td>
<td>0.03%</td>
</tr>
<tr>
<td>3</td>
<td>Common Equity</td>
<td>4,415,000</td>
<td>51.38%</td>
<td>42.07%</td>
<td>10.50%</td>
<td>5.39%</td>
<td>4.42%</td>
<td>1.6367</td>
<td>7.23%</td>
</tr>
<tr>
<td>4</td>
<td>Total Permanent Capital</td>
<td>$8,593,000</td>
<td>100.00%</td>
<td>100.00%</td>
<td>100.00%</td>
<td>100.00%</td>
<td>100.00%</td>
<td>1.0000</td>
<td>0.06%</td>
</tr>
<tr>
<td>5</td>
<td>Short Term Debt</td>
<td>184,000</td>
<td>1.75%</td>
<td>3.52%</td>
<td>0.06%</td>
<td>1.0000</td>
<td>0.06%</td>
<td>1.0000</td>
<td>0.06%</td>
</tr>
<tr>
<td>6</td>
<td>Deferred Income Taxes</td>
<td>1,667,000</td>
<td>15.89%</td>
<td>0.00%</td>
<td>0.00%</td>
<td>1.0000</td>
<td>0.00%</td>
<td>1.0000</td>
<td>0.00%</td>
</tr>
<tr>
<td>7</td>
<td>Deferred Income Taxes - MBT</td>
<td>-</td>
<td>0.00%</td>
<td>0.00%</td>
<td>0.00%</td>
<td>1.0000</td>
<td>0.00%</td>
<td>1.0000</td>
<td>0.00%</td>
</tr>
<tr>
<td>8</td>
<td>Job Develop, Investment Tax Credit</td>
<td>25,000</td>
<td>0.24%</td>
<td>5.70%</td>
<td>0.01%</td>
<td>1.0000</td>
<td>0.01%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Preferred Stock</td>
<td>-</td>
<td>0.00%</td>
<td>4.46%</td>
<td>0.00%</td>
<td>1.6367</td>
<td>0.00%</td>
<td>1.6367</td>
<td>0.00%</td>
</tr>
<tr>
<td>10</td>
<td>Common Equity</td>
<td>25,000</td>
<td>0.24%</td>
<td>10.50%</td>
<td>0.02%</td>
<td>1.6367</td>
<td>0.04%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Total Capitalization</td>
<td>$10,494,000</td>
<td>100.00%</td>
<td>6.78%</td>
<td>9.62%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: Ex. A-61 (DVR-13)
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-16794

PROOF OF SERVICE

STATE OF MICHIGAN

) SS

COUNTY OF JACKSON

Dorothy H. Wright, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on January 24, 2012, 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 same upon the Honorable Sharon L. Feldman at the address listed in Attachment 1 hereto by depositing the same in the United States mail in the City of Jackson, Michigan with first-class postage thereon fully paid.

Dorothy H. Wright

Subscribed and sworn to before me this 24th day of January, 2012.

Sharon K. Davis, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 07/28/16
Acting in the County of Jackson
Administrative Law Judge

Sharon L. Feldman, ALJ
State Office of Administrative Hearings and Rules
6545 Mercantile Way, Suite 14
P.O. Box 30221
Lansing, MI 48909
E-Mail: feldmans@michigan.gov

Counsel for the Michigan Public Service Commission Staff

Patricia S. Barone, Esq.
Robert W. Beach, Esq.
Brian W. Farkas, Esq.
Assistant Attorneys General
Public Service Division
6520 Mercantile Way, Suite 1
Lansing, MI 48911
E-Mail: baronep@michigan.gov
totoraitisb@michigan.gov
farkasb@michigan.gov
mpsceredratecase@michigan.gov

Michigan Public Service Commission Staff

Dr. Nicholas Nwabueze
Brian Welke
Regulated Energy Division
Michigan Public Service Commission
6545 Mercantile Way
P.O. Box 30221
Lansing, MI 48909
E-Mail: nwabuezen1@michigan.gov
welkeb1@michigan.gov

Counsel for Energy Michigan

Eric J. Schneidewind, Esq.
Varnum, Riddering, Schmidt & Howlett LLP
The Victor Center, Suite 810
201 N. Washington Square
Lansing, MI 48933
E-Mail: ejschneidewind@varnumlaw.com

Counsel for the Kroger Company

Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202
E-Mail: kboehm@bkllawfirm.com

Anthony J. Szilagyi, Esq.
Law Offices of Anthony J. Szilagyi, PLLC
110 South Clemens Avenue
Lansing, MI 48912
E-Mail: szilagyiaw@sbcglobal.net

Consultant for the Kroger Company

Kevin Higgins
Energy Strategies, LLC
Parkside Towers
215 South State Street, Suite 200
Salt Lake City, Utah 84111
E-Mail: khiggins@energystrat.com

Counsel for Midland Cogeneration Venture Limited Partnership (“MCV”)

Richard J. Aaron, Esq.
Warner Norcross & Judd LLP
120 N. Washington Sq., Ste. 410
Lansing, MI 48933
E-Mail: raaron@wnj.com

David R. Whitfield, Esq.
Warner Norcross & Judd LLP
111 Lyon Street, NW, Suite 900
Grand Rapids, MI 49503-2487
E-Mail: dwhitfield@wnj.com

Gary B. Pasek, Esq.
Midland Cogeneration Venture LP
100 Progress Place
Midland, MI 48640
E-Mail: gbpasek@midcogen.com
Counsel for the Association of Businesses Advocating Tariff Equity (“ABATE”)

Robert A. W. Strong, Esq.
Clark Hill PLC
151 S. Old Woodward Ave., Suite 200
Birmingham, MI 48009
E-Mail: rstrong@clarkhill.com

Consultant for the Association of Businesses Advocating Tariff Equity (“ABATE”)

James T. Selecky
Brubaker & Associates, Inc.

Physical Address
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

Mailing Address
P. O. Box 412000
St. Louis, MO 63141-2000
E-Mail: jtslecky@consultbai.com

Counsel for Hemlock Semiconductor Corporation

Jennifer Utter Heston, Esq.
Samantha A. Kopacz, Esq.
Fraser, Trebilcock, Davis & Dunlap, P.C.
124 West Allegan Street, Ste. 1000
Lansing, MI 48933
E-Mail: jheston@fraserlawfirm.com
skopacz@fraserlawfirm.com

Counsel for Attorney General, Bill Schuette

Michael E. Moody, Esq.
Assistant Attorney General
Environment, Natural Resources, and Agriculture Division
6th Floor Williams Building
525 W. Ottawa Street
P.O. Box 30755
Lansing, MI 48909
E-Mail: moodym2@michigan.gov

Consultant for Attorney General, Bill Schuette

Sebastian Coppola, President
Corporate Analytics
1359 Springwood Lane
Rochester Hills, MI 48309
E-mail: sebcoppola@corplytics.com

Counsel for the Municipal Coalition

Leland R. Rosier, Esq.
Clark Hill PLC
212 E. Grand River Avenue
Lansing, MI 48906-4328
E-Mail: lrrosier@clarkhill.com

Counsel for the Michigan State Utility Workers Council, Utility Workers of America, AFL-CIO

Steven D. Weyhing, Esq.
Kelley Cawthorne, PLLC
208 N. Capitol Avenue, Third Floor
Lansing, MI 48933-1356
E-mail: sweeney@kelley-cawthorne.com

Counsel for the Michigan Environmental Council (“MEC”) and the Natural Resources Defense Council (“NRDC”)

Christopher M. Bzdok, Esq.
Ruth Ann Liebziet, Legal Assistant
Olson, Bzdok & Howard, P.C.
420 E. Front Street
Traverse City, MI 49686
E-Mail: chris@envlaw.com
ruthann@envlaw.com
Counsel for the Michigan Community Action Agency Association (“MCAAA”)

Don L. Keskey, Esq.
Public Law Resource Center PLLC
505 N. Capitol Avenue
Lansing, MI  48933-1209
E-Mail:
donkeskey@publiclawresourcecenter.com