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
distribution of natural gas and for other relief

Case No. U-15986

DIRECT TESTIMONY

HISTORICAL YEAR

AND

PROJECTED TEST YEAR

OF

DANIEL S. ALFRED
ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business address.
A. Daniel S. Alfred, One Energy Plaza, Jackson, Michigan.

Q. By whom are you employed and in what capacity?
A. I am employed by Consumers Energy Company ("Consumers Energy" or "the Company") as a Senior Rate Analyst.

Q. Please describe your educational background.
A. I received a Bachelor of Business Administration in Accounting degree in 1993 from Eastern Michigan University. I received a Master of Business Administration degree with an emphasis in finance from Eastern Michigan University in April of 2003.

Q. Please describe your business experience.
A. In March 1994, I joined American International Airways as a financial analyst. My duties there included assisting with the closing of the accounting books on a monthly basis, assistance with all audits, and special projects.

From June of 1995 to January of 1997 I was employed as a retail accountant with Borders Books and Music. My responsibilities there included the oversight of forty retail stores with the specific tasks of preparing monthly financials, expense control, and summary reports distributed to upper management.

From January 1997 to January 1998 I was employed as an accounting analyst with Diversey Lever Company. My responsibilities there included assisting with the closing of the accounting books, subsidiary accounting, and special projects.

In January of 1998 I joined Consumers Energy as a Rate Analyst in the Financial Analysis and Planning Section of the Rates Department and was promoted to General Rate Analyst in October of 1999. During August of 2001, I transferred to a position in
the Revenue Requirements section of the Rates Department. In February of 2004, I was promoted to my current position as a Senior Rate Analyst in the Revenue section of the Rates and Business Support Department.

Q. What are your responsibilities within the Revenue section?

A. I am responsible for developing analyses related to the Company's revenue requirements and preparing electric and gas rate case filings at the Michigan Public Service Commission ("MPSC"). In addition, I prepare special studies involving financial and ratemaking analyses in response to requests internal and external to the Company.

Q. During your tenure with Consumers, have you testified in any utility proceeding before the Michigan Public Service Commission?

A. Yes. I testified in the following proceedings:

<table>
<thead>
<tr>
<th>Case Number</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Case No. U-13730</td>
<td>Gas General Rate Case</td>
</tr>
<tr>
<td>2. Case No. U-14126</td>
<td>Enhanced Security Costs</td>
</tr>
<tr>
<td>3. Case No. U-14148</td>
<td>10(d)4 Regulatory Asset Recovery</td>
</tr>
<tr>
<td>4. Case No. U-14347</td>
<td>Electric General Rate Case</td>
</tr>
<tr>
<td>5. Case No. U-15245</td>
<td>Electric General Rate Case</td>
</tr>
</tbody>
</table>

Q. What is the purpose of your testimony in this proceeding?

A. My testimony identifies and supports the Part I exhibits required by the Commission’s Order in Case No. U-15895 which revised the standard filing requirements for gas and electric utilities. Namely, my testimony is divided into two sections to address the requisite exhibits and supporting testimony on the historical period results and the projected test year pursuant to Order No. U-15895. As discussed below, I am proposing the projected test year be the 12 months ended September, 2010.
Q. Please describe the requirements.

A. To comply with the historical requirements, my testimony presents the revenue deficiency for the actual historical period. To comply with the projected test year filing requirements, my testimony presents and explains how the revenue deficiency for a future September, 2010 Test Year was developed. I will also reconcile the historic and projected test year periods. The Company demonstrates in this filing that it requires a rate increase to its gas tariffs, in order to earn a just and reasonable return.

Q. What is the actual historical year used in the exhibits and supporting testimony?

A. Calendar year 2008.

Q. Why was 2008 selected as the actual historical year?

A. This was the most recent calendar historical period that could be used for the filing.

Q. What is the Projected Test Year used in this case?

A. The Company is using the 12 months ended September, 2010 Test Year in this proceeding for final relief.

Q. Would a historical Test Year provide an adequate basis for final relief in this case?

A. No. Using a historical Test Year for final relief would be wholly inadequate, because it would ignore known changes including, among other things: i) general inflation; ii) the significant construction expenditures and related rate base growth the Company has incurred and will be incurring in 2009, and 2010; iii) reduced throughput levels; and iv) significant increases to uncollectible accounts expense.
Q. Please identify the exhibits that you are sponsoring to comply with the Commission’s standardized filing requirements related to the Historical Year.

A. The following exhibits are being submitted to satisfy the historical year requirements:

- Exhibit A-1 (DSA-1), Schedule A-1 Computation of Gas Revenue Deficiency for the Year Ended December 31, 2008
- Exhibit A-1 (DSA-2), Schedule A-2 Financial Metrics - Gas Results Only
- Exhibit A-2 (DSA-3), Schedule B-1 Average Rate Base for the Year Ended December 31, 2008
- Exhibit A-2 (DSA-4), Schedule B-2 Rate Base – Average Plant and Other Assets for the Year Ended December 31, 2008
- Exhibit A-2 (DSA-5), Schedule B-3 Rate Base – Average Depreciation Reserve and Other Deductions for the Year Ended December 31, 2008
- Exhibit A-3 (DSA-7), Schedule C-1 Adjusted Net Operating Income for the Year Ended December 31, 2008
- Exhibit A-3 (DSA-8), Schedule C-2 Computation of Revenue Multiplier for the Year Ended December 31, 2008
- Exhibit A-3 (DSA-9), Schedule C-3 Historical Sales Revenue for the Year Ended December 31, 2008
- Exhibit A-3 (DSA-10), Schedule C-4 Cost of Gas Sold for the Year Ended December 31, 2008
- Exhibit A-3 (DSA-11), Schedule C-5 Other Operation and Maintenance Expense for the Year Ended December 31, 2008
<table>
<thead>
<tr>
<th></th>
<th>Exhibit A-3 (DSA-12),</th>
<th>Schedule C-6 Depreciation and Amortization Expense for the Year Ended December 31, 2008</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-13),</td>
<td>Schedule C-7 General Taxes for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-14),</td>
<td>Schedule C-8 Federal Income Taxes for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-15),</td>
<td>Schedule C-9 State Income Taxes for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-16),</td>
<td>Schedule C-10 City Income Taxes for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-17),</td>
<td>Schedule C-11 Allowance for Funds Used During Construction for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-18),</td>
<td>Schedule C-12 Compensation Disallowances for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-19),</td>
<td>Schedule C-13 Non-Utility Expenditures Included in Operating Income for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-20),</td>
<td>Schedule C-14 Advertising Classification for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-21),</td>
<td>Schedule C-15 Corporate Giving and Communications – Staff Salaries for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-22),</td>
<td>Schedule C-16 Jobwork Revenues/Expenses – Bring Above the Line for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-23),</td>
<td>Schedule C-17 Adjusted Net Operating Income Income Tax Savings for the Year Ended December 31, 2008</td>
</tr>
<tr>
<td></td>
<td>Exhibit A-3 (DSA-24),</td>
<td>Schedule C-18 Tax Effect of Interest Synchronization Adjustment for the Year Ended December 31, 2008</td>
</tr>
</tbody>
</table>
Q. Were these exhibits prepared by you or under your direction and supervision?
A. Yes, they were.

Q. Based on your review of the historical year exhibits, was there a revenue deficiency in the historical year?
A. Yes. The historical year revenue deficiency for the 12-month period ended December 31, 2008 period was $47,232,000.
Q. Please summarize the key findings for the historical year exhibits.

A. These historical year exhibits demonstrate that for the year ended December 31, 2008:

<table>
<thead>
<tr>
<th></th>
<th>(Thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Base</td>
<td>$2,634,902</td>
</tr>
<tr>
<td>Rate of Return</td>
<td>6.85%</td>
</tr>
<tr>
<td>Income Required</td>
<td>180,373</td>
</tr>
<tr>
<td>Adjusted NOI</td>
<td>151,437</td>
</tr>
<tr>
<td>Income Deficiency</td>
<td>28,935</td>
</tr>
<tr>
<td>Revenue Multiplier</td>
<td>1.6323</td>
</tr>
<tr>
<td>Revenue Deficiency</td>
<td>$47,232</td>
</tr>
</tbody>
</table>

Q. Do the above results include typical ratemaking adjustments such as weather, annualization of rate increases, inflation, and regulatory disallowances?

A. No. The historical year results are per Company booked results. Ratemaking adjustments are recognized, where appropriate, in the second part of my testimony, which covers the Projected Test Year.

**Projected Test Year**

Q. Please identify the exhibits that you are sponsoring to comply with the Commission’s filing requirements related to supporting the September 2010 Projected Test Year.

A. The following exhibits are being submitted to support the projected test year:

- Exhibit A-6 (DSA-37), Schedule A-1 Computation of Gas Revenue Deficiency for Test Year – September 2010
- Exhibit A-6 (DSA-38), Schedule A-2 Comparison of Gas Revenue Deficiency Between Historical Period and Test Period
- Exhibit A-6 (DSA-39), Schedule A-3 Reconciliation of Gas Revenue Deficiency – Historical Period Versus Test Year
- Exhibit A-6 (DSA-39a), Schedule A-3a Financial Metrics – Ratemaking Basis
- Exhibit A-7 (DSA-40), Schedule B-1 Development of Rate Base for Test Year – 2010
Exhibit A-7 (DSA-41) Schedule B1a Development of Rate Base for Test Year – September 2010
Exhibit A-7 (DSA-42) Schedule B2 Projected Utility Plant Test Year – September 2010
Exhibit A-7 (DSA-43) Schedule B3 Projected Accumulated for Depreciation Test Year – September 2010
Exhibit A-7 (DSA-44), Schedule B-4 Gas Balance Sheet Working Capital Summary - Test Year – September 2010
Exhibit A-8 (DSA-45), Schedule C-1 Projected Net Operating Income Test Year – September 2010
Exhibit A-8 (DSA-46), Schedule C-2 Computation of Revenue Multiplier Test Year – September 2010
Exhibit A-8 (DSA-47), Schedule C-3 Projected Sales Revenue Test Year – September 2010
Exhibit A-8 (DSA-48), Schedule C-4 Projected Cost of Gas Sold Test Year – September 2010
Exhibit A-8 (DSA-49), Schedule C-5 Projected Other O&M Expense Test Year – September 2010
Exhibit A-8 (DSA-50), Schedule C-6 Projected Depreciation & Amortization Expense Test Year – September 2010
Exhibit A-8 (DSA-51), Schedule C-7 Projected General Taxes Test Year – September 2010
Exhibit A-8 (DSA-52), Schedule C-8 Projected Federal Income Taxes Test Year – September 2010
Exhibit A-8 (DSA-53), Schedule C-9 Projected State Income Taxes Test Year – September 2010
Exhibit A-8 (DSA-54), Schedule C-10 Projected Other (or Local) Taxes Test Year – September 2010
Exhibit A-8 (DSA-55), Schedule C-11 Projected AFUDC Test Year – September 2010
Exhibit A-8 (DSA-56), Schedule C-12 Adjusted Net Operating Income Pro Forma Interest Adjustment for Test Year – September 2010
Q. Were these exhibits prepared by you or under your direction and supervision?
A. Yes, they were.

Q. Please summarize the key findings for the projected test year exhibits.
A. These Projected Test Year September 2010 exhibits demonstrate the following key points for the test year ended September 30, 2010:

<table>
<thead>
<tr>
<th>(Thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Base</td>
</tr>
<tr>
<td>$2,904,857</td>
</tr>
<tr>
<td>Rate of Return</td>
</tr>
<tr>
<td>7.28%</td>
</tr>
<tr>
<td>Income required</td>
</tr>
<tr>
<td>$211,531</td>
</tr>
<tr>
<td>Adjusted Net Operating Income</td>
</tr>
<tr>
<td>141,422</td>
</tr>
<tr>
<td>Income Deficiency</td>
</tr>
<tr>
<td>$70,109</td>
</tr>
<tr>
<td>Revenue Multiplier</td>
</tr>
<tr>
<td>1.6323</td>
</tr>
<tr>
<td>Revenue Deficiency</td>
</tr>
<tr>
<td>$114,441</td>
</tr>
</tbody>
</table>

The data for the above are presented on Exhibit A-6 (DSA-37), Schedule A-1.

Q. Please explain Exhibit A-6 (DSA-38), Schedule A-2.
A. This exhibit presents the Projected Test Year revenue deficiency for Consumers of $114,441,000 (line 10, column (d)). Column (b) of the exhibit presents pertinent rate base and rate of return amounts for the historical period. Column (c) shows the changes resulting from normalizations and other adjustments as supported by the various Company witnesses that are required to represent the Projected Test Year. Column (d) then displays the 2010 rate base, income requirement, and revenue requirement.
Q. What are the major differences between Historical Year and Projected Test Year results shown on Exhibit A-6 (DSA-38), Schedule A-2?

A. The comparison of historical and projected results in Exhibit A-6 (DSA-38) shows that the adjusted Net Operating Income (“NOI”) (Line 7) decreases by $10 million between the 2008 Historical Year and the Projected Test Year. In addition, rate base increases by $270 million (Line 4) and the rate of return increases from 6.85% to 7.28% (Line 5).

Q. Please describe Exhibit A-6 (DSA-39), Schedule A-3.

A. This exhibit reconciles the various components of the calculation of the 2008 and 2010 revenue deficiencies from Exhibit A-6 (DSA-38), Schedule A-2.

Q. Please explain Exhibit A-6 (DSA-39a), Schedule A-3a.

A. This exhibit provides the financial metrics and statistics for the Projected Test Year as required by the new filing requirements.

Q. Please describe Exhibit A-7 (DSA-40), Schedule B-1.

A. Schedule B-1 is a summary presentation of the Projected Test Year average rate base. The adjusted 2010 rate base is $2,904,857,000.

Q. Please describe Exhibit A-7 (DSA-41), Schedule B-1a.

A. Schedule B-1a shows the development of the Projected Test Year average rate base in an alternate presentation to Exhibit A-7 (DSA-40), Schedule B-1. Line 4, Column (b) shows the average rate base for the historical 2008 period. Lines 5-10, column (b) show the changes to historical rate base necessary to develop the Projected Test Year rate base. Changes to historical net plant figures are driven by proposed capital expenditures for 2009-2010 as provided to me by Company witnesses Hice and Harry. The change in the unamortized balance related to Manufactured Gas Plant (“MGP”) remediation was
provided to me by Company witness Daniel Harry. The decrease in working capital over historical levels is driven by lower gas prices as provided to me by Company witness David Howard, which also results in lower accounts payable balances. Working capital has also been reduced to reflect the adjustments to the 2008 working capital in order to appropriately represent the gas portion of Mr. Rao's recommended level of accounts receivable financing. Lastly, I have adjusted historical working capital to reflect balance sheet account balances which have been or will be reduced to a zero balance. Line 11, column (b) shows Test Year rate base in the amount of $2,904,857,000.

Q. Please describe how the Projected Test Year average plant and related amounts were developed.

A. Gas plant and reserve balances for the September 2010 Projected Test Year were developed and averaged by taking the average of the balances at December 31, 2009 and September 30, 2010. To accomplish this, actual 2008 plant balances were used as the starting point. Plant additions for 2009 and year-to-date September, 2010 were added, and 2009 and year-to-date September, 2010 retirements were deducted. The 2009 and year-to-date September 2010 construction expenditures and associated plant additions are supported in the testimony of Company witnesses Hice and Harry.

Q. Please describe Exhibit A-7 (DSA-42), Schedule B-2.

A. Schedule B-2 shows the projected utility plant that is developed in my Exhibit A-7 (DSA-40), Schedule B-1, which I described earlier.
Q. Please describe Exhibit A-7 (DSA-43), Schedule B-3.
A. Schedule B-3 presents the projected accumulated provision for depreciation for the Projected Test Year by type. The total on Line 11 is pulled forward to Line 4 on Exhibit A-7 (DSA-40), Schedule B-1.

Q. Please explain Exhibit A-7 (DSA-44), Schedule B-4.
A. Exhibit A-6 (DSA-44), Schedule B-4 develops the Company’s proposed Projected Test Year balance sheet working capital requirement. The starting point is the historical 2008 working capital column (b) adjusted to: i) restate gas stored underground inventory costs as provided to me by Company witness Howard; ii) reflect decreased associated accounts payable; iii) reflect a decrease in accounts receivable; and iii) reflect changes to accrued taxes and other current liabilities.

Q. Based on your analyses, what is Consumers Energy’s adjusted net operating income for the Projected Test Year?
A. The adjusted net operating income for the Projected Test Year is shown on line 20, column (b) of Exhibit A-8 (DSA-45), Schedule C-1. The total operating revenues on Line 4 are netted against total operating expenses on Line 13 to arrive at Net Operating Income on Line 14. From there, further adjustments are made on Lines 15-18 utilizing normal ratemaking practices to arrive at Adjusted Operating Income on Line 20 of $141,422,000.
Q. Please describe Exhibit A-8 (DSA-46), Schedule C-2.

A. Exhibit A-8 (DSA-46), Schedule C-2, shows the development of the revenue multiplier for the Projected Test Year. The Michigan Business Tax (“MBT”) is effectively 5.75% in 2010. The resulting revenue multiplier is 1.6323.

Q. Please explain the projected sales revenue shown on Exhibit A-8 (DSA-47), Schedule C-3.

A. This exhibit presents the revenues that are derived from the sales forecast developed and supported by Company witness Linda Clark.

Q. Please explain Exhibit A-8 (DSA-49) Schedule C-5?

A. Schedule C-5 presents the projected other operations and maintenance expense “O&M” for the Projected Test Year. The amounts on Lines 1 through 14 were provided to me by Company witnesses Hice, Kops, and Harry and are supported in their testimony and exhibits.

Q. Please explain Exhibit A-8 (DSA-48) Schedule C-4 and Exhibits A-8 (DSA-50) through (DSA-55), Schedules C-5 through C-11.

A. These exhibits present the following: Projected Cost of Gas Sold, Projected Depreciation & Amortization Expense, Projected General Taxes, Projected Federal Income Taxes, Projected State Income Taxes, Projected Other (or Local) Taxes, and Projected AFUDC. The total from each exhibit is pulled forward to the Company’s Income Statement presentation on Exhibit A-8 (DSA-45), Schedule C-1.
Q. Please describe Exhibit A-8 (DSA-56), Schedule C-12.
A. Exhibit A-8 (DSA-56), Schedule C-12 shows the calculation of pro forma interest expense for the Projected Test Year (and the corresponding change in federal income tax).

Q. Please describe Exhibit A-8 (DSA-57), Schedule C-13.
A. Exhibit A-8 (DSA-57), Schedule C-13 shows the calculation of the tax effect of the interest synchronization adjustment for the Projected Test Year.

Q. Why are Exhibits A-8 (DSA-56), Schedule C-12 and (DSA-57), Schedule C-13 included in the presentation?
A. These exhibits are part of the Gas Filing Requirements. The intent of the exhibits is to align the interest expense and the associated tax benefits with the amount of rate base that is financed with the debt portion of the Company’s proposed cost of money.

Q. Is the Company required to reconcile the historic and projected test years?
A. Yes. Per the new filing requirements adopted by the Commission, if a rate application is not based on a calendar test year, the utility should include a complete reconciliation of the projected test year to the most recent historical calendar year. My Exhibit A-8 (DSA-59), Schedule C-14 serves this purpose to comply with the new filing requirements.

Q. Please explain Exhibit A-8 (DSA-58), Schedule C-14.
A. Exhibit A-8 (DSA-58), Schedule C-14 presents the reconciliation of the Historical 2008 Year to the Projected September 2010 Test Year. The amounts within this schedule are taken from other exhibits in my presentation. The exhibit is laid out with revenues in columns (b) through (d), expenses in columns (e) through (l), and the resulting Adjusted
NOI in column (o). The exhibit begins with the historical year on line 1, makes normalizing adjustments on lines 2-9, test year adjustments on lines 12-23, and calculates Test Year Net Operating Income on line 25. In general, the revenues and expenses adjustments are shown with their accompanying tax impacts to arrive at adjusted net operating income. Line 1 represents the 2008 Historic Year Net Income and the amount of $153.2 million in column (o) ties to the Historic Net Operating Income on Line 16 of Exhibit A-3 (DSA-7), Schedule C-1.

Q. Please explain the normalizing adjustments for Schedule C-14.

A. These adjustments located on Lines 2 through 9 are made to comply with prior Commission orders and follow traditional ratemaking practices such as removing regulatory disallowances, bringing certain revenues “above the line”, adjusting historical year 2008 revenues to reflect “normal” weather, and resulting adjustments to income taxes. The Compensation Disallowances on Line 3 are supported by Schedule C-12. The Dues, Donations, Advertising Disallowances on Line 4 are supported by Schedule C-13. The Corporate Giving & Communications on Line 5 are supported by Schedule C-15. Bringing the Jobwork Revenues/Expenses on Line 6 above the line is supported by Schedule C-16. The Revenue Adjustment on Line 7 is supported by Schedule C-20. The Pro Forma Income Tax Savings and Interest Synchronization on Lines 8 and 9 are longstanding ratemaking conventions. The Total Operating Income of $151.4 million on Line 11 column (o) ties to the Adjusted Operating Income on Line 25 of Exhibit A-3 (DSA-7), Schedule C-1.
Q. Please explain the Projected Test Year Adjustments on Schedule C-14.

A. These adjustments represent the movement from the Normalized Historical Operating Income to the Projected Test Year Net Operating Income. The numbers on Lines 12 through 23 are generated from the Property Model, my own exhibits, and through the exhibits of Company witnesses Clark, Harry, Hice, Howard, and Kops. The Test Year Net Operating Income on Line 25 is the result of netting the test year adjustments on Line 24 against the Normalized Historical Operating Income on Line 11. The Projected Test Year Net Operating Income of $141.4 million on Line 25 column (o) ties to the Adjusted Net Operating Income on Line 20 of Exhibit A-8 (DSA-45), Schedule C-1.

Q. Please explain the adjustments made for the Projected Test Year on Schedule C-1.

A. Lines 12 through 14 represent the changes in revenues to the test year and show a reduction overall. The reduction is driven mainly by the reduced sales forecast supported by Company witness Clark.

Line 15 represents a reduction to Company Use and Lost and Unaccounted For (“LUAF”) of $14 million from the historical 2008 level and is supported by Company witness Hice.

Line 16 represents an increase to Other Operating & Maintenance expense of approximately $65 million and is supported in the presentations of Company witnesses Hice, Harry, and Kops. Company witness Hice supports the gas operations expenses, Company witness Harry the corporate expenses, and Company witness Kops supports the projected benefits expenses.

Line 17 represents the change in the book depreciation expense generated by the property model for the projected test year. The Company is using the new depreciation...
rates issued in the Final Order for Case No. U-15629 dated December 23, 2008. Along with the reduced depreciation rates, additional capital expenditures along with assumed plant retirements fuel the change in depreciation expense.

Line 18 represents Real and Personal Property Taxes and this amount also comes from the property model.

Line 19 represents other general taxes and is almost identical to the historical year.

Line 20 represents Michigan Business Tax Adjustments and is supported by Company witness Theodore Vogel.

Line 21 represents AFUDC and this amount is generated from the property model.

Line 22 represents the changes in Pro Forma Interest Adjustment and Interest Synchronization for the Projected Test Year and is supported by Schedules C-12 and C-13 respectively.

Line 23 represents the Federal Income Tax Adjustments which result from all the other changes in revenue and expense levels for the Projected Test Year.

Q. Please explain Exhibit A-9 (DSA-59), Schedule E-1.

A. Exhibit A-9 (DSA-59), Schedule E-1 displays the operating revenues for the Projected Test Year. The Total Gas Operating Revenue on Line 35 column (j) ties to the revenues on Exhibit A-8 (DSA-47), Schedule C-3, Line 3.

Q. Does this conclude your testimony in this proceeding?

A. Yes, it does.
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
distribution of natural gas and for other
relief.                                      
________________________________________

DIRECT TESTIMONY

OF

LINDA J. CLARK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business address.
A. Linda J. Clark, One Energy Plaza, Jackson, Michigan.

Q. By whom are you employed?
A. Consumers Energy Company (the “Company” or “Consumers Energy”).

Q. What is your position with the Company?
A. I am a Senior Business Support Consultant in the Rates and Business Support Department.

Q. Please summarize your education and business experience.
A. I received a Bachelor of Science Degree in Secondary Education from Western Michigan University in 1970 with a minor in mathematics. I have been employed by Consumers Energy since 1978 and have held a variety of positions with increasing responsibilities. Initially I worked as a scheduler in the Automotive, Facilities and Storeroom areas in the Grand Rapids office. In 1980, I transferred to Jackson and worked as an engineering technician in the Gas Distribution System Engineering Department primarily performing system load flow studies. In 1984, I transferred to the Corporate Planning Department. In that position I provided support with data analyses related to the gas sales forecast, the electric sales forecast, and the electric peak demand forecast. On a monthly basis since 1984, I have analyzed and weather normalized the Company’s gas and electric sales data for Senior Management. From 1992 through 1995, I also forecasted the electric peak hourly demand. My responsibilities evolved over time to include the daily tracking of gas and electric sendout, monthly analyses and weather normalization of gas and electric deliveries. In addition, starting in January 1997, I worked in the Business Intelligence Department in Dearborn doing international research. In November 2000, I was promoted to Senior Business Support Consultant in the Gas Business Support Department where my
primary responsibility is preparing the Company’s official gas sales forecast. In 2003, Gas Business Support was consolidated within the Rates and Business Support Department. I also prepare special studies for the Vice President of that department.


Q. Have you attended any seminars?
A. Yes, I have attended a forecasting workshop conducted by Regional Economic Research (RER), now Itron.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to present Consumers Energy’s forecast of gas deliveries volumes for the test year of twelve months ending September 30, 2010.

Q. What was your role in the development of this forecast?
A. I am responsible for the development of the gas sales and transportation forecasts. My job responsibilities include making sure that the forecasts are based upon consistent and logical assumptions, periodically reviewing the methodology, and refining or updating the methods when necessary.

Q. Has the forecast which you are presenting been approved by the Company?
A. Yes, the forecast for calendar years 2009-2015 was approved by the Company’s management in May 2009.
Q. Are you sponsoring any exhibits?
A. Yes, I am sponsoring the following exhibits:

   Exhibit A-10 (LJC-1) Michigan Winters

   Exhibit A-11 (LJC-2) Schedule E-2, Gas Deliveries Forecasts (MMcf) with 15-Year and 30-Year Weather Normals (October 2009 – September 2010)

   Exhibit A-12 (LJC-3) Schedule E-3, Gas Deliveries Forecasts (MMcf) by Customer Class with 15-year and 30-year Weather Normals (October 2009 – September 2010)

   Exhibit A-13 (LJC-4) Schedule E-4, Gas Deliveries Customers by Class (October 2009 – September 2010)

   Exhibit A-14 (LJC-5) Schedule E-5, Test Year September 2010 Forecasted Volumes by Rate Code 15-Year Weather Normal

   Exhibit A-15 (LJC-6) Schedule E-6, Test Year September 2010 Forecasted Customers by Rate Code


   Exhibit A-17 (LJC-8) Schedule E-8, Average Residential Space Heating Use Per Customer and Year-Over-Year Percent Change (1980 – 2014)

   Exhibit A-17a (LJC-9) Automotive Manufacturing

Q. Were these exhibits prepared by you, or under your supervision?
A. Yes.

Q. Please summarize Consumers Energy’s gas forecasting process.
A. The techniques used to forecast gas deliveries (sales plus transportation) vary from customer class to customer class based upon the availability of information. However, in general, these forecasts were based primarily on regression analyses. Examples of the independent variables used in the forecast models include economic variables from the Company’s current economic service provider, IHS Global Insight, and heating degree-days.
The four major classes of gas deliveries that are forecasted are residential, commercial, industrial, and interdepartmental. Some of the classes are broken down into more detail. These annual forecasts are developed from cycle-billed data from customer records. The annual forecasts are allocated to monthly volumes using factors developed from weather normalized historical data.

Three primary methodologies were used to forecast 2009 – 2015 gas deliveries. One method used was regression analysis, a mathematical and statistical tool that correlates the relationship between dependent variables (deliveries, average use, or customers) and the independent variables (economics and/or weather). By applying these relationships to the forecast of the independent variables, projections of the dependent variable can be made. Regression models were used to forecast residential space heating use, residential domestic use, residential A-1 use, commercial deliveries, industrial other deliveries, and General Motors deliveries. The second methodology, exponential smoothing, was used to forecast residential space heating customers, domestic customers, A-1 customers, commercial customers, industrial customers, and Dow sales. Exponential smoothing simply involves the use of the exponentially weighted moving average model, which assigns heavier weights to recent values of the dependent variable. Professional judgment was used to forecast Detroit Edison and interdepartmental deliveries. When none of the above methodologies is completely applicable, the forecaster must rely on techniques such as trending, and looking at current and future events affecting sales.

After the cycle-billed forecast of total deliveries by class is developed, a forecast of transportation, by class, is made by trending historical percentages. The gas sales forecast is the gas deliveries forecast less the gas transportation forecast. If necessary, the impacts
of future factors or "forward-looking items" not fully present in past data, such as energy
optimization impacts, are developed independently and directly applied as adjustments to
the base forecast.

Q. Is the gas deliveries forecast a weather-normalized forecast?
A. Yes. The deliveries forecast is a weather normalized forecast, based on the assumption
that normal weather will occur during the forecast period.

Q. Please discuss your review of the weather normalization of the gas deliveries in the
forecasting process.
A. It should be noted that actual heating degree days and actual deliveries are used in the
regression models, not weather-normalized volumes. The monthly historical gas deliveries
are weather normalized using coefficients developed from regression analyses of monthly
historical data for residential space heating use per customer, residential A-1 use per
customer, commercial deliveries, industrial other deliveries and General Motors deliveries.
These coefficients are reviewed frequently. The calculated coefficients are multiplied by
the difference between actual heating degree days for the month, and the normal monthly
heating degree days. This correction is then added or subtracted to the monthly use or
deliveries, depending whether the actual heating degree days were below or above normal,
respectively.

The normal level of heating degree days used to forecast gas deliveries in the
forecast models was developed by taking an average of the most recent 15 years (1994 –
2008) of historical heating degree days. In 2003, I chose a 15-year period for purposes of
the gas deliveries forecast rather than a 30-year period based on the conclusion that using a
15-year period is, at present, a better predictor of future normal weather that can be
expected during the forecast period, and therefore gas deliveries. In fact, for eight of the
last eleven years, the 15-year average of heating degree days has been a better predictor of
the next year’s weather than the 30-year average. Using a longer period, such as the
current NOAA (National Oceanic and Atmospheric Administration) 30-year normal of
1971-2000 (NOAA updates the 30-year normal after the end of the decade), or the most
recent 30-years of 1979 - 2008, would result in overstating the deliveries during the
forecast period as a result of including the colder 1970s, and excluding or diluting the
impacts of recent warmer weather. While use of a longer historical time period, such as a
30-year, may be appropriate for other purposes, I concluded that the 30-year period should
not be used for forecasting annual deliveries that would occur if normal weather were
experienced during the forecast period.

At the American Meteorological Society’s 89th Annual meeting in January 2009,
Dr. Anthony Arguez from NOAA’s National Climatic Data Center presented a paper
entitled, “On Improving NOAA’s Climate Normals: An Introduction to ‘Optimal
Normals’ of Temperature.” In the paper, Dr. Arguez states, “There is a clear need to
compute new Climate Normals that (1) are representative of the current state of the climate
at the time they are reported and/or (2) explicitly accommodate the prospect of a changing
climate. NCDC scientists are currently developing a new suite of experimental products
called ‘Optimal Normals’ that attempt to address these two issues.” Dr. Arguez further
states that, “The results presented here all suggest that the current NOAA 1971-2000
Climate Normals are unlikely to be adequate indicators of either the current state of the
climate or future climate conditions. The suite of experimental products known as
Optimal Normals is an attempt to rectify this problem, and an explicit acknowledgment of
the limitations of the traditional 30-year average Climate Normals.” The first wave of Optimal Normals will be available in 2009. In addition, a second wave of Optimal Normals are currently in the development phase, and should be available prior to the 2011 release of NOAA’s official 30-year Climate Normals for the 1981-2010 period.

From the NOAA chart on Exhibit A-10 (LJC-1) (http://climvis.ncdc.noaa.gov/cgi-bin/cag3/hr-display3.pl), it can be seen that winter (December – February) temperatures have trended warmer for the entire state of Michigan since 1970. The trend has been a gain of +1.0 degrees per decade since 1970.

Q. Please describe Exhibits A-11 (LJC-2) through A-13 (LJC-4).

A. In accordance with the MPSC’s standard rate-case filing requirements for gas utilities, Exhibit A-11 (LJC-2) is the monthly calendar gas deliveries, gas sales, and gas transportation forecasts for the test year of twelve months ending September 30, 2010, using both a 15-year, and a 30-year, weather normal. The 15-year weather normal forecast, which the Company believes is superior, is -1.9 Bcf lower than the 30-year weather normal forecast due to the aforementioned warming trend.

Exhibit A-12 (LJC-3) shows the total monthly calendar deliveries by class for the twelve months ended September 30, 2010, using both a 15-year, and a 30-year, weather normal. Exhibit A-13 (LJC-4) shows the customer forecasts by class for the period October 2009 through September 2010.
Q. Exhibits A-11(LJC-2) through A-13 (LJC-4) show calendar month volumes and customers, whereas earlier you said the forecast was cycle-billed. Does this mean you developed two forecasts, one for calendar and one for cycle-billed?

A. No. There is one forecast developed. Annual cycle-billed deliveries are forecasted by class with “use,” “sales,” and “customer” models because cycle-billed data are the purest form of data from the customer records. The annual results are then allocated to monthly cycle-billed volumes using weather adjusted historical percentages. For example, January’s allocation for a certain class may be 16% of that class’s annual deliveries, whereas the August allocation may be only 3% based on average weather adjusted deliveries. Any known adjustments to deliveries are made to the cycle-billed forecast prior to converting cycle-billed to calendar.

The annual total calendar deliveries forecast is simply an adaptation of the cycle-billed forecast. Annual total calendar deliveries are projected using linear regression with cycle-billed deliveries as the independent variable. Calendar deliveries will be slightly different than cycle-billed deliveries because of unbilled deliveries. (Unbilled deliveries are gas volumes delivered to customers during the month, but not billed in that calendar month.) Monthly calendar allocation factors developed from weather adjusted historical calendar data are applied to the annual values to arrive at a monthly calendar deliveries forecast in the same manner as they are for the cycle-billed deliveries.

Next, transportation is estimated based on its historical relationship to total deliveries. The percentage of monthly deliveries attributable to transportation is calculated and then projected for the forecast years. Transportation is then subtracted from deliveries to determine the sales portion of the forecast.
Q. How were monthly calendar sales by class developed?

A. The cycle-billed sales by class and unbilled sales are used to create calendar sales by class. Two constraints are placed on this analysis. First, the sum of monthly sales by class must equal the total monthly calendar numbers. Second, the sum of the annual calendar total sales by class must equal the annual calendar total sales forecast after completing the translation process from cycle-billed. This approach assures that the cycle-billed forecast and the calendar forecast are consistent.

Q. How was the residential sales forecast developed?

A. The residential gas sales are separated into three categories. Residential gas space heating sales represent gas used by residential customers primarily for space heating. Residential domestic sales represent gas used by residential customers who do not heat with gas. Residential multi-family sales represent gas used by customers at centrally-metered apartment complexes.

For the space heating category, a forecast of average consumption was based upon an annual regression model from 1997 through 2008 using heating degree-days, Michigan single family housing starts, and Michigan average household size as the independent variables. The customer forecast for this category was based upon an exponential smoothing model. The residential space heating gas deliveries forecast is the product of the average consumption and customer forecasts.

For residential domestic and multi-family customers, the forecasts were also developed through the use of exponential smoothing models. Regression analysis was used to forecast domestic and multi-family average consumption.
Q. Please describe how the projection of the commercial sector was made.

A. For the commercial category, a forecast of deliveries was based upon an annual regression model from 2001 through 2008 using heating degree days, Michigan population, and Michigan unemployment percent as the independent variables.

Q. Please describe in general terms how the projections of the industrial sectors were made.

A. The gas deliveries forecasts for the General Motors class was based upon an annual regression model from 2002 through 2008 using Michigan transportation equipment employment, the Michigan industrial production index, and Michigan unemployment percent as the independent variables. The forecast for the Industrial Other (industrial deliveries excluding deliveries to GM, Dow, and Detroit Edison) class was based upon an annual regression model from 2002 through 2008 using the Michigan unemployment percent and heating degree days as independent variables. The gas sales forecast to Dow Chemical was developed using an exponential smoothing model. Professional judgment was used to develop the forecast of Detroit Edison gas sales.

Q. Please describe how interdepartmental sales were forecasted.

A. The interdepartmental category represents gas used by Consumers Energy in areas not related to the gas business. Interdepartmental deliveries are projected to remain at a level similar to recent history, based on professional judgment.

Q. What are your projections of the number of gas customers?

A. Customer forecasts by class are shown on Exhibit A-12 (LJC-3). The forecasts for residential, commercial and industrial customers are developed using exponential smoothing models.
Q. Please explain Exhibit A-14 (LJC-5) and Exhibit A-15 (LJC-6).

A. These Exhibits show the breakdown of sales and customers into specific rate codes for purposes of rate design. Exhibit A-14 (LJC-5) is the above mentioned forecasted class volumes further broken down by rate code. After developing the forecast for commercial, interdepartmental, and industrial classes, the sales for these classes are further split into rate classes or rate codes, for purposes of rate design. (The three residential class forecasts are essentially the rate codes for residential customers.) As shown on Exhibit A-14 (LJC-5), commercial, interdepartmental, and industrial sales are split into General Service Rates GS-1, GS-2 and GS-3. Transportation sales are also split into specific rate codes, however because of aggregation, it is necessary to split out the aggregate sales rates into the residential, General Service and Transport rate classes. As a result, Transportation sales are split into Residential rates A and A-1, General Service rates GS-1, GS-2 and GS-3, and transport rates ST, LT and XLT as shown on Exhibit A-14 (LJC-5) page 2 of 2. The sales for each class are allocated to each of the specific rate code designations on the basis of historical weather normalized calendar sales. (See WP-LJC-5 and WP-LJC-6) The number of customers for each class on Exhibit A-15 (LJC-6) is similarly determined using actual historic bills. (See WP-LJC-2 and WP-LJC-3)

Q. Were any other adjustments made to sales for purposes of projecting sales for the rate code level for the split test year October 2009 through September 2010?

A. Yes, sales were adjusted to reflect the modification of transportation contracts that will move sales from Rate LT to ST to reflect the movement of a customer from the Rate LT to ST. An additional sales adjustment was made to reflect the movement of a customer with
seven locations (1 master account and 6 contiguous accounts) from LT to XLT. (See WP-LJC-3 and WP-LJC-6 & 7).

Q. Please summarize the difference between the 2008 weather-normalized gas deliveries and the 2009-2010 gas deliveries forecast.

A. For the test year of October 2009 through September 30, 2010, gas deliveries are forecasted to be 271.6 Bcf, which is 25.7 Bcf lower than the 2008 weather-normalized level of 297.2 Bcf, using a 15-year weather normal. Fifty-eight percent, or 14.9 Bcf, of the total deliveries reduction is in the industrial sector. As can be seen on Exhibit A-16 (LJC-7), the first four months of 2009, have already dropped significantly from the first four months of 2008. Weather-normalized total gas deliveries are down -6.5%, or -10.4 Bcf, for the first four months of 2009. Year-to-date April 2009 weather-normalized industrial deliveries are down -17.3%, or -4.3 Bcf, from April 2008. In general, the forecasted reduction is due to the normal efficiency gains from newer appliances, conservation, and Michigan’s economic conditions including population trends and housing activity. More than two-thirds of all counties in Michigan lost population last year, according to estimates released by the U.S. Census Bureau in March 2009. The battered economy has affected all three major gas sectors -- residential, commercial and industrial. Michigan unemployment reached 12.6% in March. Michigan’s foreclosure rate in April ranked eleventh in the nation. In April, Don Grimes, senior research specialist at the University of Michigan’s Institute for Research on Labor, Employment and the Economy, predicted the state’s jobless level will reach 15% by this fall. In May, Economist David Littman, senior economist at the Mackinac Center for Public Policy, predicted that unemployment in Michigan could approach 17% to 20% by year end.
Exhibit A-17 (LJC-8) shows that in the early 1980s during that recessionary period, residential use per customer declined an average -4.5% per year, and a similar decline of -3.0% per year is expected for the 2005 – 2009 period. From 1980 through 2008, average residential use per customer has declined -1.3% per year. Average residential use per customer is forecasted to decline -1.3% from September 2009 to September 2010.

Historically, the percentage decline in commercial average use per customer has been the same as the residential decline. From 1980 through 2008, commercial average use per customer has declined -1.3% per year. For the test year ending September 2010, commercial average use is forecasted to decline -1.6% from the previous twelve months.

Because the industrial sector is so heterogeneous, use per customer is not an appropriate measure of industrial activity. Instead, the number of industrial customers is a better indicator of gas load. Since reaching their peak of 8,566 in February 1997, Consumers Energy industrial customers have declined about -1.1% per year. Compared to the 2008 base year average, industrial customers are forecasted to be down -330 by the end of the test year. See Exhibit A-15 (LJC-6). That’s an average annual decline of about -2.2% since 2008.

Exhibit A-17a (LJC-9) is a map showing the concentration of automotive manufacturing in the Midwest. The sharp dependence of Michigan’s economy on the Detroit Big Three (General Motors, Ford, and Chrysler) automakers has been well documented. Michigan’s overall employment growth has closely tracked Detroit Big Three domestic automotive sales since 1991, up to and including the recent plunge in sales. George Fulton, research professor at U of M’s Institute for Research on Labor, Employment and the Economy, predicts the sales plunge will be accompanied by a loss of
239,000 jobs from the end of 2008 to the end of 2009 – the largest job loss since at least 1956. By the end of 2010, Michigan’s automotive industry will employ barely one-half of its 2007 work force. Some experts believe that possibly 30% of the nation’s small-middle-market automotive suppliers will not exist one year from now unless the U.S. government takes additional steps to extend the $5 billion supplier support program to Tier 2 and Tier 3 suppliers.

Q. Does this complete your testimony?

A. Yes, it does.
S T A T E  O F  M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for the
distribution of natural gas and for other relief

Case No. U-15986

DIRECT TESTIMONY

OF

DANIEL L. HARRY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business address.
A. Daniel L. Harry, One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed, and in what capacity?
A. I am the Director of Business Support for Consumers Energy Company (“Consumers Energy” or the “Company”).

Q. How long have you been employed by Consumers Energy?
A. I have been employed by Consumers Energy since 1999.

Q. Please state your educational background.
A. I graduated from Central Michigan University with a Bachelor of Science Business Administration degree with a major in accounting.

Q. What other professional designations do you hold?
A. I am a Certified Public Accountant registered in Michigan.

Q. What are your responsibilities in your current position?
A. As Director of Business Support, I am responsible for the development of the Gas Utility strategic plans, budgets, outlooks and forecasts. I am also responsible for the development of the electric and gas deliveries and revenue forecasts as well as the ongoing financial analysis of gas utility operations.

Q. Please describe your prior work experience.
A. I have held my current position since 2008. From 2003 to 2008, I was the Director of Accounting Research for Consumers Energy responsible for implementation of new accounting standards and determined the appropriate accounting for major transactions. From 2001 to 2003, I was a Senior Accountant responsible for electric revenue and
power cost accounting. From 1999 to 2001, I was a General Accountant responsible for external reporting, accounting research, and subsidiary accounting.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony is in six parts. In Part 1, I am presenting testimony supporting the 2010 test year operation and maintenance ("O&M") expense levels for Corporate Services, uncollectible expense, Manufactured Gas Plant amortization and direct Project Management costs and accounts receivable sale costs. In Part 2, I am presenting testimony supporting Corporate Services capital expenditures. In Part 3, I am presenting testimony addressing book depreciation expense. In Part 4, I am presenting testimony regarding asset retirement obligations, transition adjustment, and ongoing accounting entries. In Part 5, I am presenting testimony demonstrating Consumer Energy’s compliance with the guidelines for intercompany transactions between affiliates as ordered by the Commission. In Part 6, I am presenting testimony requesting accounting approval for the use of regulatory assets or regulatory liabilities, as needed, by the Uncollectible True-Up Mechanism ("UTM") and the Revenue Decoupling Mechanism ("RDM") proposed in Company witness Pender’s testimony.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

- **Exhibit A-18 (DLH-1)** Summary of Gas O&M Expense for the Years 2008-2009 and 12-Months Ended September 2010
- **Exhibit A-19 (DLH-2)** Gas Uncollectible Expense for the Years 2008-2009 and 12-Months Ended September 2010
- **Exhibit A-20(DLH-3)** Manufactured Gas Plant Amortization Schedule and Direct Project Management Costs 1999 through 2010
Q. Were these exhibits prepared by you or at your direction?
A. Yes.

PART 1 – 2010 TEST YEAR O&M

Q. Please describe Exhibit A-18 (DLH-1).
A. Exhibit A-18 (DLH-1) is an exhibit that summarizes the Company's total 2008-2010 gas O&M expense for Corporate Services, uncollectible expense, Manufactured Gas Plant amortization & direct Project Management costs and accounts receivable sale costs. On Page 1 of this exhibit, column (a) provides the O&M expense category, column (b) provides the 2008 Actual O&M, column (c) provides the 2009 O&M, column (d) provides the 12-months ended September 2010 Test Year O&M of $78.0 million.
Column (e) provides the source reference. These expense categories are discussed in more detail below.

**Corporate Services O&M**

Q. Please describe the areas included within the Corporate Services category you are addressing?

A. Corporate Services include those areas common to the administrative functions of a regulated corporation such as Consumers Energy. These areas include Human Resources and Administrative Services, Internal Control & Compliance, Legal, Corporate Risk Management, the Corporate Secretary, Governmental and Public Affairs, Investor Relations and Treasury, Controller’s Area, Rates and Regulation/Regulatory Affairs, Corporate Tax, Financial Planning, General Activities costs, Information Services and Technology (IS&T), Administrative and Other costs, and Comprehensive Enterprise Application (CEA) costs.

Q. Please provide a brief overview of these areas.

A. These areas function as follows:

- Human Resources and Administrative Services – This area includes services for approximately 8,000 employees and Human Resource offices at 23 locations. This area provides for the development of workforce strategies including recruiting, hiring, training and development, and succession planning. This area also includes Labor Relations which provides for all interaction with the unionized workforce. Also included are compliance assurance (in addition to the compliance area described below) which addresses all legal and regulatory programs affecting the Company including Equal Employment Opportunity, Americans With Disabilities
Act, and Family and Medical Leave Act. Safety and health issues, compensation and benefits administration, corporate employee travel, and security administration are also provided.

- Internal Control & Compliance – This area provides Internal Audit functions (appraisal of the effectiveness of financial controls) and the Internal Control functions.

- Legal – This area provides advice and counsel in the areas pertaining to the legal rights and responsibilities of the Company at the state and federal levels.

- Corporate Risk Management – This area provides services for corporate insurance programs, surety bonds and review of commodity and credit risks associated with natural gas, electric fuel and power purchases. Gas and electric insurance programs include the premiums for property and casualty insurance paid to cover the business.

The major insurance coverage for the Company include:

- All risk property damage
- Directors and Officers liability insurance
- Public liability insurance
- Workers’ compensation insurance
- Fiduciary liability insurance
- Fidelity insurance

- Corporate Secretary – This area provides management for corporate records in various media, imaging services, corporate library services, maintenance of all minutes and records related to board of directors and shareholder meetings,
incorporations and dissolutions; and functions as the shareholder transfer agent providing registrar services.

- Governmental and Public Affairs – This area provides or includes all aspects of internal and external communications: public media relations and inquiries, corporate news releases, employee and executive communications, trade association dues and memberships, regulatory commission expense, charitable contributions, foundations and community programs.

- Investor Relations and Treasury – This area includes all aspects of Company financing and cash management, processing of Company credit facilities, treasury operations including initiating cash wire transfer transactions, processing checks for deposit, maintenance of all bank account related activities, borrowing and investing, and investor relations.

- Controller’s Area – This area includes the preparation and control of accounting records, including financial statements and reports and the administration of accounting systems. These systems include budgeting and management reporting, general ledger, accounts payable, payroll, fixed assets and customer billing and payment processing. Financial and regulatory reporting are also included in this area.

- Rates and Regulation/Regulatory Affairs – This area includes preparation of utility strategic plans, budgets and forecasts, determination and management of tariffs, management of regulatory filings, communications with regulatory staffs and standard setters, and management of the interface between the Company and the regulatory staffs.
• Corporate Tax – This area includes all aspects of compliance with federal, state and local income, sales and use, property tax, franchise and excise taxes, book accounting for taxes, tax planning of transactions, tax research and the analysis of tax legislation and regulations, and the management and negotiation of tax audits and tax litigation.

• Financial Planning includes financial and strategic planning, specialized financial studies and analyses, as well as rate case, regulatory, rating agency and investor support.

• General Activities costs are an aggregation of expense and credits that are not attributable to any one department, but are incurred on behalf of the Company as a whole. Examples include Corporate Services labor and expenses capitalized credits to O&M, billing credits for administrative and general labor, expenses and outside services as part of a full-cost loading adder, Senior Management time and expenses, and Board of Director costs.

• IS&T expenses – This area provides for the Corporate Service portion of IS&T costs supporting the standard utility information technology infrastructure services. These services include expenditures for the technical employees as well as contracted labor that provides all support activities. This includes technical management and support of computing technology, voice and data networks, and other enterprise information technology sponsored functions such as security, control processes, user technical support and information technology management and planning. It provides such Company-customer communications as telecommunications service, call centers, voice response units, and internet processes. This area also provides
communications link between Company offices for workstations and field remote
work reporting and assignment devices as well as generic software licensing for tools
that personnel use directly in the course of their job responsibility.

- Administrative and Other costs are for utility management and support staff, AGA
  Association dues, and intervener funding for the GCR cases.
- CEA costs are for the Company’s existing core business processes and information
  technology. The core business processes include several major functional areas
  within the Company such as finance, purchasing/supply chain, customer service,
  human resources and payroll, utility asset construction and maintenance work
  management. Production installation occurred July 2008. Ongoing costs include
  system operating and maintenance costs.

Q. How are Corporate Services expenses allocated between the Company’s electric and gas
businesses?

A. Allocations are developed based upon the type of cost. For example, billing costs are
allocated based on customer counts for the electric and gas businesses, benefits are
allocated based on either employee counts or labor, general costs are allocated on the
Massachusetts Formula, with other costs being direct charged for identified activities,
allocated based on capital and O&M spending levels and special studies. Page 1, line 1,
column (b) of Exhibit A-18 (DLH-1) provides the utility historical gas portion of
Corporate Services expenses for the year 2008 of $38.4 million. Line 1, column (c)
reflects the gas 2009 projected O&M expense of $35.7 million. The 12-months ended
September 2010 amount on line 1 column (d) is $36.7 million.
**Gas Uncollectible Expense**

Q. What is included in the Company’s Gas uncollectible expense?

A. Uncollectible expense is made up of two components. The first component is the write-off of customer accounts receivable balances that are deemed uncollectible. The second component reflects changes during the period in the uncollectible reserve account. The balance in the uncollectible reserve represents the estimate of existing receivables that will not be collected in the future and is recorded as an offset to the carrying value of accounts receivable. A change in the reserve account increases or decreases uncollectible expense. Together, the two components represent the estimate of the current period impact on the Company’s income from customer accounts that will not be collected.

Q. What has been the past practice of calculating uncollectible expense for ratemaking purposes?

A. The past practice has been to use a three-year average Bad Debt Loss Ratio (BDLR) for uncollectible write-offs and also excluded the change in the uncollectible reserve.

Q. Does this method provide a reasonable estimate of uncollectible expense?

A. Due to the rapidly deteriorating economy in Michigan, using a historical average does not provide a reasonable estimate of future uncollectible expense. The averaging of past expenses can be appropriate in instances when the expense for previous years go both up and down, creating some likelihood that the future period’s activity will be similar to the past period. Presently, however, the Company’s uncollectible expense experience has shown significant annual increases over the prior year during the three-year period from 2006 through 2008.
Q. What are the drivers of increasing uncollectible expense?

A. The drivers of increasing uncollectible expense are Michigan’s declining economy and related rapidly increasing unemployment. The economy and the high rate of unemployment have impacted an increasing number of customers who are struggling to pay their bills. The Michigan seasonally adjusted unemployment rate has increased from 7.6% in March 2008 to 12.6% in March 2009 according to an April 15, 2009 release by the Michigan Department of Energy, Labor & Economic Growth. As of March 2009, Michigan’s unemployed labor force now totals 609,000 people (a 62% increase over March 2008) and represents a significant percentage of Consumers Energy’s 1.7 million gas customer base. Based on Global Insight’s January 2009 report, Michigan’s unemployment rate is projected to remain above 11% through 2010.

Q. Please describe the Company’s recent experience as it relates to gas uncollectible expense.

A. Recent levels of gas uncollectible expense have increased every year over the past five years, going from $12.4 million in 2004 to $26.1 million in 2008 on line 3 of Exhibit A-19 (DLH-2), a 115% increase.

Q. What is the Company’s projection of uncollectible expense for the 12-month period ending September 2010?

A. The Company has projected that uncollectible expense will be established in rates in this proceeding at $34.87 million for the 12-months ending September 2010 (see line 3, Exhibit A-19 (DLH-2)).
Q. Is $34.87 million on line 3, Exhibit A-19 (DLH-2) a reasonable amount?

A. Yes. The projected increased level of uncollectible accounts will be significantly higher than what would be determined using the historical method of a three-year average BDLR. This level reflects the continuing decline of Michigan’s economy discussed above. In 2008, Consumers Energy saw a 36% increase in uncollectible write-off expense over the prior year. The rate at which uncollectible write-off expense is increasing is in proportion to Michigan’s economy and the recent 62% increase in Michigan’s unemployed workforce. Consumers Energy’s forecast of uncollectible write-off expense for 2009 represents a 30% increase over 2008. Because unemployment is predicted to remain at levels similar to 2009 through the end of 2010, the Company applied the BDLR for the 2009 forecast to arrive at the projected uncollectible write-off expense for the 12-months ending September 2010.

Due to the uncertainty around the length and depth of Michigan’s economic downturn and the volatility of uncollectible write-off expense, the Company is proposing that the Commission approve a UTM (defined earlier on Page 2) to protect Consumers Energy and its customers from the potential future volatility in uncollectible expense. Further details are discussed by Company witness Pender.

Q. Why is it appropriate to include the change in the uncollectible reserve when establishing rates?

A. The change in the uncollectible reserve should be included for four reasons.

First, the uncollectible reserve includes the change in expected uncollectible write-offs for current billings to make up for the six-month lag in recording uncollectible write-offs (period of trying to collect arrearages). Therefore, the change in the reserve
accounts for the six-month lag in recording the write-off expense and better matches expense to the revenues being recorded and included in rates. Ignoring this portion of expense in times of increasing Uncollectible expense only adds to the shortfall of rates versus actual expenses. Under Generally Accepted Accounting Principles (GAAP), the future uncollectible is realized at the time revenue is billed, based on past experience. GAAP requires financials to be on an accrual basis. There are numerous items in the determination of operating income that are accrued and not recognized on a cash basis. As an example and also a direct link to the issue of uncollectible expense, revenues that are included in the calculation of operating income and the revenue deficiency are also partly non-cash. Revenues include billed amounts that have not been collected as well as unbilled estimates. The operating revenue calculation is based on the income statement with many items that are not cash. Ignoring increases or decreases in the reserve expense misstates operating income and the revenue deficiency. The estimated uncollectible reserve expense in the income statement and the uncollectible reserve on the balance sheet are based on the most current bad debt loss ratio, and therefore is a reasonable estimate.

Second, the accrual for the Company’s portion of the PeopleCare Program is included in the reserve balance. This is the result of a reduction in the reserve to account for the bill credits provided by the Company. The reserve needs to be restored to its pre-contribution amount, resulting in an uncollectible reserve expense. The PeopleCare Program is an important program created to help Michigan families in need. If the Company did not contribute to this program, more customers would default and be shut off, increasing the write-off portion of uncollectible expense, which is included in rates.
Third, the working capital calculation utilizes the uncollectible reserve as an offset to the receivables, thereby reducing current assets, which in turn reduces the working capital allowance. Therefore recognition of the uncollectible reserve expense is essential to be consistent with the ratemaking treatment being utilized in the working capital calculation. Further, the working capital calculation is the place in rates designed to determine cash requirements, not operating income.

Fourth, from a consistency standpoint, the reserve should be in rates similar to Detroit Edison and Michigan Consolidated Gas Company.

**Manufactured Gas Plant Amortization and Direct Management Costs**

Q. How did the Commission previously address environmental investigation and remediation expenditures at former Manufactured Gas Plant (MGP) sites?

A. In Case No. U-10755, the Commission approved deferred accounting for these expenditures, with amortization over ten years, beginning the year after expenditures are incurred. The approach adopted by the Commission envisioned that prudence reviews would occur in rate cases and that following a prudence review (i) the amortization expense would be included in rates and (ii) the deferred balance would be included in rate base and would earn a return at the authorized rate of return. The approach adopted by the Commission also provided for deferred accounting and amortization of third-party recoveries in excess of the costs of recovery over ten years and deferred tax accounting. In Case No. U-13000, the Commission upheld this accounting treatment.
Q. What ratemaking treatment is the Company proposing in this proceeding for MGP third-party recoveries?

A. In Case No. U-13000, net insurance recoveries were included as an offset by the Commission in its final order. The Company’s request in this case reflects the net insurance proceeds applicable to MGP costs received to date of approximately $22.5 million as detailed on line 2 of Exhibit A-20 (DLH-3), Page 1 and totaled on line 4 of Exhibit A-20 (DLH-3), Page 2.

Q. What ratemaking treatment is the Company seeking for direct non-incremental labor and business expenses for MGP Project Management costs?

A. The Commission provided for the prospective recovery of direct non-incremental MGP Project Management costs as an O&M item in Case No. U-14547.

Q. Please explain Exhibit A-20 (DLH-3), Page 1, which provides the annual amortization of MGP-related environmental costs and the expense of the direct Project Management costs.

A. Line 1 shows deferred cash expenditures for MGP remediation costs for years 1999 - 2009. Line 2 shows the third party recoveries for the years 1999 thru 2008. Lines 3 – 14 show the amortization level of these deferred MGP remediation costs using stratified 10-year amortization periods for expenditures made through 2009. Amortization of the third-party recoveries on line 2 as shown on line 15, acts as a credit to the amortization of expenditures identified in this case. Line 16 is the net MGP amortization expense. It should be noted that until these expenditures are incorporated in a future case, the Company is required to absorb the associated carrying cost and amortization of these costs.
Q. Please explain line 17 on Page 1 of Exhibit A-20 (DLH-3).

A. Line 17 is the Project Management costs that the Commission provided for recovery as
direct costs rather than be deferred and amortized as part of its order in Case No. U14547.
The change is effective for the calendar year 2006 onward.

Q. Please explain Exhibit A-20 (DLH-3), Page 2, related to the rate base treatment.

A. Line 1 of the exhibit provides the total deferred cash expenditures for MGP remediation
costs for the years 1999 – 2009. Line 2 is the total amortization of MGP expenditures for
the years 1999–2009. Line 3 is the net unamortized MGP expenditures. Line 4 provides
net insurance recoveries for the years 1999 – 2009. Line 5 shows the total amortization
of the insurance recoveries for the years 1999 – 2009. Line 6, the sum of lines 3 – 5, is
the unamortized balance that should be included in rate base for the test year, in
accordance with the Commission’s prior orders.

Q. What ratemaking treatment is the Company proposing in this proceeding for MGP
environmental costs?

A. The Company is requesting that the Commission find (i) that the costs for the period
covering June 2007 through December 2009, as sponsored by Company witness
Kelterborn, are prudent (given that the Commission has previously approved costs
incurred through May 2007), (ii) authorize recovery of amortization expense in the
amount of $3.456 million and direct Project Management costs of $0.915 million as
provided on Exhibit A-20 (DLH-3), Page 1 and (iii) include the deferred unamortized
balance in the amount of $23.325 million in rate base as provided on Exhibit A-20
(DLH-3), Page 2.
Accounts Receivable Sale Costs

Q. What are Accounts Receivable Sale costs as shown on line 5 of Exhibit A-18 (DLH-1)?

A. Accounts Receivable Sale costs include the discount and fees incurred during the sale of accounts receivable transactions. The 2010 amount of $2.038 million as shown on line 5, column (d) of Exhibit A-18 (DLH-1) was provided by DV Rao in his testimony ($4.870 million x 41.84% gas portion).

PART 2 – CORPORATE SERVICES CAPITAL EXPENDITURES

Business Technology Solutions (BTS) and Common

Q. Please explain the capital expenditures shown on Exhibit A-21 (DLH-4) line 1.

A. Line 1 shows expenditures for Capitalized Projects, Computer Equipment, and Other Equipment.

Capitalized Projects are CEA capital costs associated with the Company’s existing core business processes and information technology discussed earlier. Also included are intangible software for electronic document retrieval and security ID and user management.

Computer Equipment includes expenditures for many different types of computing equipment located both centrally in Jackson and distributed at common locations around the Company. This equipment is required to provide secure and efficient desktop computing, field work devices, local area network operation, printing, and the management of commonly-used systems such as the radio system, voice and data network, internet provisioning, and equipment located at the central data center.

Other Equipment includes radio, telephone, and network equipment. The spending is for telecommunication equipment necessary to provide communications to
Company personnel in the field, employees between and within offices, employees with customers, and employees with outside parties including vendors, regulators, etc. It includes voice and radio communications equipment, data transmission facilities (including fiber optic network), and related technology support equipment. This equipment utilized by field personnel is of importance to not only serve customers effectively and efficiently, but also contribute to public and employee safety.

Q. Are other witnesses in this rate proceeding presenting capital projections of information technology investment?

A. Yes. Company witness Hice’s testimony describes the Company’s proposal relating to Advanced Metering Infrastructure (AMI).

Gas Corporate Services – Other

Q. Please describe the capital expenditures shown on Exhibit A-21 (DLH-4) line 5.

A. Line 5 describes Capitalized Projects, Computer and Communications Equipment.

These capitalized projects include expenditures for Central Mail Remittance (CMR), the Tax Compliance Project, implementing replacement software, and Internal Control server and system upgrade.

The CMR project includes replacing the processor servers used to run the software for processing energy payments mailed by customers. The present equipment is two years past its normal projected life. In addition, a new piece of mail extraction equipment is being purchased to allow for a larger volume of each day’s payments to be deposited by 7:30 AM allowing for more funds to have same day availability.
PART 3 – DEPRECIATION

Book Depreciation Expense

Q. What is the Company’s proposal as it relates to depreciation expense?

A. The Company is proposing depreciation expense be based on existing MPSC approved depreciation rates. If depreciation rates are updated prior to the issuance of a final order in this case, the update expense should be reflected in that order.

PART 4 - ASSET RETIREMENT OBLIGATION

SFAS No. 143

Q. Please describe SFAS No. 143, Accounting for Asset Retirement Obligations (“ARO”).

A. SFAS No. 143 is a financial reporting requirement which deals with the identification, measurement and recording of legal liabilities and offsetting incurred cost of removal associated with asset retirement. SFAS No. 143 provides that any legal obligation to incur expenditures for the removal of a long-lived tangible asset after its useful life be recorded as a liability, at its present value. ARO liabilities may be the result of enacted law, statute, ordinance, or written or oral contract.

Q. Has the Company recognized any SFAS No. 143 ARO liabilities as it relates to its gas business?

A. Yes. The Company has two such obligations. 1) closure of wells at the Northville Storage Field, and 2) movement of inside gas meters to the outside of homes.

Q. Please describe FASB Interpretation No. 47, Accounting for Conditional AROs.

A. This Interpretation clarifies that the term conditional asset retirement obligation as used in SFAS No. 143, refers to legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may
or may not be within the control of the entity. The obligation to perform the asset
retirement activity is unconditional even though uncertainty exists about the timing and
(or) method of settlement.

Q. Has the Company recognized any FASB Interpretation (“FIN”) 47 ARO liabilities as it
relates to its gas business?
A. Yes. The Company has FIN 47 ARO liabilities for asbestos abatement and cut, purge
and cap of distribution pipe.

Q. What were the effective dates of these standards for the Company?
A. SFAS No. 143 was effective January 1, 2003; FIN 47 was effective December 31, 2005.

Q. What is the accounting related to this standard?
A. The Standard requires the Company to make the following transition adjustments and
ongoing entries in its financials:

**Transition Adjustment**

1. Record a liability for the present value of the estimated future retirement cost for
assets that have a legal obligation to be removed at the end of their useful lives.

2. Record an ARO plant asset equal to the present value of the estimated future
retirement cost obligation at the time the underlying asset was put into service.

3. Record accumulated depreciation related to the ARO asset depreciation from
when the underlying asset was put into service to when this standard was adopted.

4. Reduce the existing underlying asset accumulated depreciation for the cost of
removal recorded to standard adoption date.

5. Establish a regulatory asset or regulatory liability equal to the net overage or
underage for the above four items.
**Ongoing Entries**

1. Record depreciation of the ARO assets.

2. Record accretion expense to increase ARO liabilities since the transition adjustment was recorded at present value.

3. Reduce ARO liabilities for cost of removal incurred.

4. Adjust regulatory assets/liabilities for timing difference in ARO depreciation expense and accretion compared to cost of removal included in depreciation rates.

Q. What is the impact of this accounting?

A. From a balance sheet standpoint the asset side of the balance sheet will be increased to offset the recording of ARO liabilities, when incurred. These standards are generally income statement neutral. Accordingly, regulatory assets or regulatory liabilities are established to match the timing difference of the revenue included in rates for cost of removal compared to ARO accretion and depreciation expense.

Q. What is the Company’s proposal as it relates to the accounting and ratemaking for SFAS No. 143 and FIN 47?

A. The Company seeks regulatory asset/regulatory liability treatment for the timing differences between the required accounting and the regulatory treatment for asbestos abatement and cut, cap and purge related to this Standard, consistent with the treatment previously received for existing SFAS 143 ARO’s.

Q. Was the Company directed where to ask for case by case approval for regulatory asset/liability treatment?

A. Yes. The Company’s requested regulatory asset/liability treatment for the two new items in this case is the result of the MPSC Order No. U-14292 at Page 34, that this issue would
be decided in normal Company rate proceedings versus the generic proceeding.

Technically, the Company’s request assumes that the Uniform System of Accounts
(“USA”) is amended to add regulatory asset/liability accounts prior to an order in the
current case. However, if that is not the case, deferred accounting is acceptable to fit into
the current USA. It should also be noted, that even though the USA does not include a
regulatory asset/liability account per se, it has been a long-standing practice to record
regulatory assets and liabilities in the existing deferred accounts and the utility is required
to provide a breakdown of the regulatory assets within the deferred asset account in the
P-521 at Page 232 (M).

Q. Is the Company seeking a rate increase as a result of this request?

A. No. As a practical matter, there is no rate increase required for AROs. The cost of
removal is already provided in the ratemaking process through depreciation rates.
Therefore this request is simply to recognize what is already in rates as a timing
difference with the FASB required accounting to avoid the Company having to double
record cost of removal for these items on its financials. The loss that could be suffered
just for the Cut, Purge and Cap ARO is approximately $6.4 million (pretax) on an annual
basis.

Q. In summary, what is the Company’s position as it relates to this request?

A. The Commission should at a minimum provide deferred accounting for the requested
AROs if the US-of-A are not amended by the time of the order in this case.
Q. What is the purpose of your testimony in regards to Affiliated Company Transactions?
A. I am sponsoring Exhibits A-22, (DLH-5), Exhibits A-23 (DLH-6), and Exhibits A-26 (DLH-9) to comply with the filing requirements for gas rate cases before the Michigan Public Service Commission as clarified in MPSC Case No. U-10039. I am also sponsoring two additional exhibits, Exhibits A-24, (DLH-7) and Exhibits A-25 (DLH-8), as described below.

Q. Please explain Exhibit A-22, (DLH-5).
A. Page 1 of this exhibit provides an organization chart showing the interrelationship of the affiliated companies that had transactions with Consumers Energy relative to providing/receiving services or commodities. In addition, Pages 2-3 list their affiliation, percentage ownership and purpose of business.

Q. Please explain Exhibit A-23, (DLH-6).
A. This schedule summarizes costs billed to affiliated companies (Pages 1 and 2), and payments made to affiliated companies (Page 3) for the year 2008.

**Costs Billed to Affiliated Companies**

Q. For the costs billed to affiliated companies, how are the costs classified and how are they priced?
A. These costs are classified as to whether they impact the balance sheet, other operating income, or utility operating income. These costs are all priced on a full-cost basis.

Q. What is meant by “Costs are all priced on a full-cost basis?”
A. The full-cost basis means total direct costs along with applicable overheads. For services provided, it would be primarily labor cost incurred along with allocated overheads and
employee benefits. For commodities purchased, it would be the contracted amount for
the commodity based on a negotiated purchase by the Gas Supply organization, or on the
electric side, the Power Transactions organization. Property lease is priced per contract.
Q. For commodity purchase, what is the difference between the full-cost amount and market
amount?
A. At the time of the purchase, the full-cost amount and market amount would be the same.
In other words, it is the agreed upon price between the purchaser and seller of the
commodity.
Q. Please describe the types of services performed by Consumers for affiliated companies.
A. Most services performed are: administrative services such as payroll, corporate
communications, human resources, computer services; employee benefits related to
health care, life insurance, savings plan; or professional services such as engineering,
accounting, legal, and tax.
Q. What types of billing activity are directly classified to the balance sheet?
A. These are the direct costs incurred for employee benefits or for rendering services to
affiliated companies that are separately accounted for in Consumers’ responsibility
accounting system and translate to an individualized receivable from associated
company (Account 146.XXX).
Q. What types of billing activity are classified as other operating income?
A. Billing activity classified as other operating income consists of income related to the cost
of money.
Q. Please explain the cost of money.
A. It is the recovery of Consumers Energy’s cost for the use of its funds expended to render services prior to reimbursement. This recovery is recorded in Account 419, Interest Income.

Q. What types of billing activity are classified as utility operating income?
A. Billing activity classified as utility operating income consists of overhead costs. These costs affect administrative and general expenses, and revenue accounts as shown on Exhibit A-23 (DLH-6), which impact gas and electric operations.

Q. What is the impact of this utility operating income activity on gas operations?
A. As shown on Exhibit A-24 (DLH-7), gas operations were favorably impacted by $1.06 million.

**Payments Made to Affiliated Companies**

Q. Please describe the types of goods provided by affiliates and services performed for Consumers as shown on Exhibit A-22 (DLH-6), Page 3.
A. Commodities include the purchases of electric energy. Services provided include officer services and professional services, such as accounting, engineering, finance, legal and tax.

Q. For payments made to affiliated companies, how are they classified and how are they priced?
A. These payments are classified as to whether they impact the balance sheet, other operating income or utility operating income. These payments are priced on a full-cost basis.
Q. What types of payment activity are classified as balance sheet items?
A. The payments classified as balance sheet items consist of costs deferred on the balance sheet for subsequent reclassification, amounts to be billed or amounts recorded as liabilities.

Q. What types of payments are classified as other operating income?
A. Other operating income payments consist generally of CMS Enterprises costs for Governmental Affairs, certain CMS Energy corporate costs, and engineering services.

Q. What types of payment activity are classified as utility operating income?
A. Payments classified as utility operating income consist of energy purchases and professional services.

Q. Is the “Massachusetts Formula” method used to allocate administrative costs of the parent company to Consumers Energy?
A. Yes. The “Massachusetts Formula” is used to allocate certain parent company indirect costs to its subsidiaries, which includes Consumers Energy.

Q. Why is the Massachusetts Formula method used to allocate costs?
A. This method is used to allocate indirect costs that cannot be readily identified to any particular subsidiary or affiliated company.

Q. How long has the Massachusetts Formula been used to allocate costs?
A. This allocation method has been used to allocate costs within CMS Energy since 1987.

Q. Are parent company costs that can be identified to Consumers Energy charged directly to Consumers Energy?
A. Yes. When the costs can be specifically attributed to Consumers Energy, these costs are charged directly to Consumers Energy.
Q. Why is the Massachusetts Formula method an appropriate allocation method for certain company costs?

A. This method provides a practical means to allocate a pool of common costs based on an equitable and consistent basis. Subjectivity and inability to directly charge costs is the reason the Massachusetts Formula is utilized by entities to allocate costs.

Q. Did Consumers Energy develop the Massachusetts Formula?

A. No. It was first conceived as a method for state tax administration in Massachusetts. Subsequently, the formula was adopted for allocating administrative and general expense in diversified corporations.

Q. Has the FERC approved the use of the Massachusetts Formula?

A. Yes. Examples of specific companies that have used this method include: Duke Energy, Entergy Services, Inc, San Diego Gas & Electric, and Williams Natural Gas Company.

Q. What is the impact of payments classified as utility operating income on gas operations?

A. The amount of payments applicable to gas operations for these activities is $3.28 million as shown on Exhibit A-25 (DLH-8).

Q. Please explain Exhibit A-26, (DLH-9).

A. This schedule shows the rate of return on common equity for those affiliates doing business with Consumers Energy.

Q. Is Consumers Energy in compliance with the guidelines for intercompany transactions between affiliates as ordered by the Commission in Case No. U-11916 as well as the code of conduct adopted by the Commission in MPSC Case No. U-12134?

A. To the best of my knowledge, Consumers Energy is in compliance with these guidelines.
PART 6 – UTM AND RDM ACCOUNTING

Q. Does the implementation of the UTM and RDM discussed in Company witness Pender’s testimony require any specific accounting approvals?

A. Yes. The UTM and RDM would result in deferred debits or credits until any under-recovery or over-recovery is fully collected or refunded. The Company requests approval to recognize regulatory assets or liabilities as needed to record these deferred amounts.

In the event that the annual uncollectible expense is 105% or greater than the base level of uncollectible expense approved by the Commission in this case, the excess amount would be recognized as a regulatory asset for future recovery. Conversely, if the annual uncollectible expense is 95% or less of the base uncollectible expense level, the underage would be recognized as a regulatory liability for future refund. For the RDM, if by class, the actual average Mcf usage per customer is lower or higher than the baseline average Mcf usage per customer, any difference would be recognized as a regulatory asset or liability for future recovery or refund. Any outstanding regulatory asset or liability associated with the UTM or RDM would accrue interest at the Company’s short-term borrowing rate.

Q. Does this conclude your testimony?

A. Yes.
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
distribution of natural gas and for other relief

Case No. U-15986

DIRECT TESTIMONY

OF

DONALD D. HICE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business address.

A. Donald D. Hice, 1945 W. Parnall Road, Jackson, Michigan.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”).

Q. What is your position with Consumers Energy?

A. I presently hold the Manager of Gas Asset Management position for Consumers Energy. Prior to that I was the Manager of Gas Transmission and Storage Engineering, Plant Manager of J. H. Campbell and have held various other positions beginning in 1976.

Q. What are your responsibilities as Manager of Gas Asset Management?

A. I am responsible for system capacity planning, engineering, design and standards of the Company’s gas distribution, transmission and storage systems. I also have responsibility for project management, compliance programs and engineering records.

Q. Please describe your educational background.

A. I graduated from Saginaw Valley State University with a Bachelor of Science degree in Mechanical Engineering in 1984 and from Aquinas College with a Masters of Management in 1995.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company’s request for rate relief as it relates to the Company’s regulated gas operations and the Advanced Metering Infrastructure (“AMI”) Program. My testimony is divided into three parts: first, a description of the O&M expenses related to the Company’s regulated gas operations for the test year 12 months ending September 2010; second, a description of the capital
expenditures related to the Company’s regulated gas operations through September 2010
for inclusion in the Company’s rate base; and third, a description of the O&M expenses
and capital expenditures for the Company’s AMI program projected through September
2010.

Q. Please continue.

A. The Company has projected its O&M expenses for the test year 12 months ending
September 2010 to meet customer service and safety requirements. For most Gas
Operations O&M expenses the reference point was 2008 actual O&M expenses. For
O&M expenses related to Lost and Unaccounted for Gas (“LAUF”), Company Use Gas
and Low Income Energy Efficiency Fund (“LIEEF”), the test year O&M expenses were
projected using varied techniques as more fully described later in my testimony.

Q. Please describe the methodology used to project the Company’s gas operations capital
expenditures for the year 2009 and the 9 months ending September 2010.

A. The projected capital expenditures for this period are based on investment levels
necessary to meet customer reliability, safety requirements and system demands.

Q. Please describe the methodology used to project the O&M expenses and capital
expenditures for the AMI Program?

A. The AMI Program O&M expenses for the test year 12 months ending September 2010
and the capital expenditures for the year 2009 and the 9 months ending September 2010
are projected based on the assessment, development and evaluation of system and field
equipment to be used in a pilot program discussed later in my testimony.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:
DONALD D. HICE
DIRECT TESTIMONY

1  Exhibit A-27 (DDH-1)  Summary of Projected Gas Operations and AMI Program O&M Expenses

2  Exhibit A-28 (DDH-2)  Summary of Projected Gas Division O&M Expenses

3  Exhibit A-29 (DDH-3)  Summary of Projected Gas Division O&M Expense Increases

4  Exhibit A-30 (DDH-4)  Summary of Projected Gas O&M Expenses for Lost and Unaccounted for Gas & Company Use Gas

5  Exhibit A-31 (DDH-5)  Calculation of Gas Line Loss Percentage

6  Exhibit A-32 (DDH-6)  Calculation of Allowance for Gas Use and Losses

7  Exhibit A-33 (DDH-7)  Summary of Projected Gas O&M Expenses for the AMI Program

8  Exhibit A-34 (DDH-8)  Summary of Projected Gas Operations Capital Expenditures

9  Exhibit A-35 (DDH-9)  Summary of Projected Capital Expenditures for the New Business Program

10  Exhibit A-36 (DDH-10)  Summary of Projected Capital Expenditures for the Asset Relocation Program

11  Exhibit A-37 (DDH-11)  Summary of Projected Capital Expenditures for the Regulatory Compliance Program

12  Exhibit A-38 (DDH-12)  Summary of Projected Capital Expenditures for the Material Condition Program

13  Exhibit A-39 (DDH-13)  Summary of Projected Capital Expenditures for the Capacity/Deliverability Program

14  Exhibit A-40 (DDH-14)  Summary of Projected Capital Expenditures for the Gas Operations Other Programs

15  Exhibit A-41 (DDH-15)  Summary of Projected Capital Expenditures for the Gas Business Services Programs

16  Exhibit A-42 (DDH-16)  Summary of Projected Capital Expenditures for the AMI Program

17  Exhibit A-43 (DDH-17)  AMI Program Indicative Timeline
Q. Were these exhibits prepared by you or under your supervision?
A. Yes.

Q. Please summarize your testimony.
A. First I will address the fully projected O&M expenses for the Company’s total gas operations (excluding AMI). This projection can be found in Exhibit A-27 (DDH-1), lines 1-5. The total gas operations O&M projected expenses for the 12 months ending September 2010 is $253,284,000 and is set forth in (line 5, column (c)) of that exhibit.

The total 12 months ending September 2010 projected O&M expenses for the Company’s gas operations is described on Exhibit A-27 (DDH-1) in four parts. The first part (line 1) is the Gas Division O&M expenses. These expenses are routine in nature and occur year after year at a generally consistent level. Parts two through four (lines 2-4) illustrate projected O&M expenses related to Lost and Unaccounted for Gas (“LAUF”), Company Use Gas and the Low Income Energy Efficiency Fund administered by the Commission (“LIEEF”). LAUF and Company Use Gas are shown separately in accordance with the Part III Standard Filing Requirements; and LIEEF is shown separately because the expense relating to this program remains stable over time. The O&M expenses for these parts are summarized on Exhibit A-27 (DDH-1) lines 2 – 4, respectively.

My testimony also describes the gas operations capital investments through September 2010 which are described on Exhibit A-34 (DDH-8). The total Gas Operations capital expenditures (excluding AMI) for which the Company is requesting rates recognition in this case for the year 2009 and the 9 months ending September 2010
are $233,135,000 and $193,216,000 as set forth in this exhibit on (line 8, column (b)) and (line 8, column (c)), respectively.

Finally, my testimony will also describe the projected O&M expenses and capital expenditures for which the Company is requesting rates recognition related to the AMI Program in this case. The AMI Program O&M expenses for the 12 months ending September 2010 are $854,000 and can be found on Exhibit A-27 (DDH-1), (line 6, column (c)). The AMI capital expenditures for the year 2009 and the 9 months ending September 2010 are $8,097,000 and $22,894,000, respectively, and can be found in Exhibit A-34 (DDH-8) on (line 9, column (b)) and (line 9, column (c)).

Q. Please explain the gas division O&M expenses set forth on Exhibit A-28 (DDH-2), line 6.

A. The expense levels for each of the major departments presented in Exhibit A-28 (DDH-2) were derived by starting with the 2008 level of actual O&M expenses. As shown in this exhibit, 2008 actual O&M expenses for the five major departments included in the Gas Division O&M were $196,110,000 (line 6, column (b)). These 2008 O&M expenses reflect a reasonable and appropriate level of expense for these operations. No increase has been included for the 2009 projected O&M expenses for the Company’s Gas Division. The 2009 amount of O&M for the division is $196,110,000 and can be found at line 6, column (c). Assessing the business needs required to meet customer service and safety requirements for the test year 12 months ending September 2010 resulted in the projected amount of $206,131,000 (line 6, column (d)). Despite increasing wage and salary rates that occur year after year, the Company is projecting that its O&M expenses in the Gas Division will remain at 2008 levels in all but two departments within the division. Maintaining 2008 expense levels for a majority of the Gas Division
departments reflect actions and initiatives such as productivity increases and O&M cost
control. The projected increases for two areas in Gas Energy Operations and Gas
Customer Operations, are necessary to meet customer service and to mitigate risks
identified on our Gas Transmission and Storage system which will be discussed in more
detail later in my testimony.

Q. Please briefly describe the activities of each of the Gas Division departments as listed on
Exhibit A-28 (DDH-2).

A. There are five major departments in the Gas Division:

1. Gas Energy Operations
2. Gas Energy Delivery
3. Gas Customer Operations (excluding Uncollectible Write-Offs)
4. Gas Management Services
5. Gas Business Services

Q. Please describe the activities of the Gas Energy Operations department.

A. The Gas Energy Operations department includes all field and administrative support for
operating, maintaining and constructing the distribution mains and transmission
pipelines, gas service lines, storage wells, compressors and other infrastructure involved
in receiving gas from our suppliers and delivering it to our customers safely and reliably.

Included in this department, in addition to gas mains and pipelines and other
infrastructure, are metering and regulation, new connection design and installation,
customer metering, work scheduling and field dispatching and training and employee
development. The Appliance Service Plan program (“ASP”) is also part of the Gas
Energy Operations category.
Q. What operating sections are included in the Gas Energy Operations department?

A. The Gas Energy Operations department is composed of the following four major sections:

- Gas Transmission and Storage
- Energy Services
- Operation Services
- Employee Development and Skilling

Q. Please describe the activities of these sections within the Gas Energy Operations department.

A. Gas Transmission and Storage ("Gas T&S") operates and maintains high pressure gas lines to move gas purchased from suppliers into and out of underground storage fields through the use of large compressor stations. It is these large compressor stations that consume fuel gas (company use gas). Many work activities are performed in Gas T&S to keep this system running safely, efficiently and reliably. Routine maintenance and compliance work is required along with unscheduled or demand repairs. There are also O&M costs involved in providing gas measurement and regulation field activities and corrosion control. The Pipeline Integrity Program, mandated by the federal Department of Transportation acting through the Office of Pipeline Safety, is part of this section.

The Energy Services section receives the gas from the Gas T&S section for delivery to residential, commercial and industrial customers. The Energy Services section constructs, operates and maintains the Company’s distribution mains and services, customer meters and other associated equipment. This section performs routine maintenance and maintenance required by regulations. Included in these activities are
cathodic protection (which works to prevent corrosion of steel pipe), leak detection
surveys and repairs, and distribution pipeline integrity compliance work. Other
significant activities in the Energy Services section include staking of mains and services,
damage repairs and code maintenance work on mains, services, risers, regulators and
meters required to comply with safety standards and Commission commitments. In
addition the Energy Services section performs work associated with meters and meter
stands, meter reading, commercial and industrial gas pressure regulation and monitoring,
turning on gas meters, gas leak response, and relighting customer’s appliances. The
expenses related to the ASP program are also in the Energy Services section.

The Operations Services section provides scheduling and dispatching services,
contractor management services, residential meter expertise and design of residential and
commercial new service connection requests.

The Employee Development and Skilling section manages the Company’s
workers training programs including operator training and all other field work
development and skills training.

Q. Please explain the difference between the 2008 actual and the 12 month ending
September 2010 O&M levels for Gas Energy Operations as displayed on Exhibit A-28
(DDH-2), line 1.

A. The increased O&M expenses for 12 month ending September 2010 occurs in three
programs. The three programs are:

- Storage Well Integrity
- Compressor Engine Overhauls
- Low Frequency ERW Pipe
Q. Please explain the O&M increase associated with the Storage Well Integrity program.

A. Storage Well Integrity consists of well logging and well maintenance. Well logging and well maintenance are activities performed to ensure the integrity of the storage wells and the ability of the wells to deliver gas during the winter. Well logging is an industry term used to describe the process to assess the storage well integrity, similar to the work performed to assess the integrity of transmission pipelines. The primary purpose is to assess storage well material condition so remedial actions can be taken as needed before the well integrity is lost. Well maintenance is work performed in conjunction with the well logging to remove solids and scale buildup in the well that is produced during the normal process of withdrawing gas from storage. Solids and scale buildup reduce the ability of a field to deliver gas. Well maintenance activities mitigate the risk of the well not being able to deliver gas as expected.

Q. What is the benefit to the customer for these additional Storage Well Integrity expenses?

A. First, the potential for gas migrating into geological zones where it may not be recoverable or possibly migrating to the surface are reduced. Secondly, should a loss of well integrity occur, the field where the well is located would not be available to service the system. The supply loss from the field would need to be made up from other sources driving up the cost of gas to the customer. Storage Well Integrity activities are designed to minimize these risks.

Q. What amount of increase are you proposing in the Storage Well Integrity program?

A. The proposed increase associated with the Storage Well Integrity program is $2,000,000 as set forth on exhibit A-29 (DDH-3), (line 1, column (b)).
Q. What is the projected duration of the proposed Storage Well Integrity program O&M expenses?

A. The proposed program and associated expenses would continue at this level into future years.

Q. Please explain the O&M increase associated with the Compressor Engine Overhauls program?

A. The Gas T&S system utilizes large engines to run compressors to move gas purchased from suppliers into and out of underground storage fields. These engines need to be rebuilt on a periodic basis to reduce the likelihood of catastrophic failures, extend the long term running life of the engine and improve engine fuel efficiency and engine availability. A majority of the engine fleet currently have running hours that exceed the Original Equipment Manufacturer’s recommendation for an engine overhaul. The Company is projecting a program to address our current backlog of engines needing overhauls.

Q. What amount of increase are you proposing in the Compressor Engine Overhauls program?

A. The proposed increase associated with the Compressor Engine Overhauls program is $3,500,000 as can be found on exhibit A-29 (DDH-3), (line 2, column (b)).

Q. What is the projected duration of the proposed Compressor Engine Overhauls program O&M expenses?

A. The proposed program and associated expenses would continue at this level for approximately five years. The program level and associated expenses would be evaluated again in five years.
Q. Please explain the O&M increase associated with the Low Frequency ERW Pipe program being projected.

A. The Consumers Energy storage fields contain pipe that was manufactured by a process known as low frequency Electric Resistance Welding (ERW). Low frequency ERW pipe produced prior to 1970 has a history of seam defects. In October of 2007 we experienced a rupture in our Salem Fields with the root cause being selective seam corrosion in a low frequency ERW, pre-1970 vintage pipe. A 10 year program to assess the pre-1970 vintage low frequency ERW pipe in our storage fields and take corrective actions as necessary will be required to rectify the condition. The projected O&M expenses are intended to implement an in-line inspection program to assess the condition of our non-High Consequence Area storage lines with respect to corrosion and seam defects and to perform valve maintenance on the associate pipelines. The assessment process will require scheduled outages in the individual fields which provide an economic opportunity to perform additional, above required, valve maintenance.

Q. Please explain what you mean by “High Consequence Area.”

A. Relative to the Pipeline Integrity Program, gas transmission pipelines or pipeline sections are categorized as High Consequence Area (HCA) or non-High Consequence Area (non-HCA). The physical characteristics, operating pressure and the population density surrounding the pipelines and pipeline sections are analyzed to determine if it is considered HCA or non-HCA.

Q. Are High Consequence Area storage lines being assessed similarly?

A. Yes. High Consequence Area storage lines are assessed as part of the Company’s Pipeline Integrity Program.
Q. What level of O&M expense is the Company projecting for the Low Frequency ERW Pipe Program?

A. $2,900,000 as can be found on Exhibit A-29 (DDH-3), (line 3, column (b)).

Q. What is the projected duration of the proposed Low Frequency ERW Pipe program O&M expenses?

A. The proposed program and associated expenses would continue at this level for approximately ten years. The program level and associated expenses would be evaluated based on the assessments and analysis performed in the first ten years.

Q. The second department listed within the Gas Division is the Gas Energy Delivery department, set forth on Exhibit A-28 (DDH-2), (line 2). Please describe the activities of the Gas Energy Delivery department.

A. Gas Energy Delivery provides centralized planning, budgeting, engineering, engineering support and design services for the Gas Division.

Q. What operating sections are included in the Gas Energy Delivery department?

A. The Gas Energy Delivery department is composed of the following three major sections:

- Gas Asset Management
- Work Planning & Business Management
- Strategy & Portfolio Management

Q. Please describe the activities of these sections in more detail.

A. Gas Asset Management provides gas transmission engineering of the storage, compression, metering and regulation, and pipeline assets and other associated facilities. This section also provides program management and oversight for the Company’s gas assets. Included are activities associated with establishing work activities for gas
compliance related programs such as Pipeline Integrity and administration of asset
damage prevention. Additionally, Gas Asset Management provides necessary expertise
and services in the areas of distribution system engineering and technical design
standards. This organization has responsibilities for interfacing with the Commission
Gas Safety Staff and the federal Office of Pipeline Safety acting through the Pipeline and
Hazardous Materials Safety Administration (PHMSA) on regulatory compliance issues,
and security administration. Gas Asset Management also performs system load studies
and initiates augmentation projects to ensure the capacity of the gas distribution system
can meet customer demands.

Work Planning and Business Management provides comprehensive work
planning and budget services along with departmental self-auditing and Sarbanes Oxley
compliance support. Additionally, certain centralized information technology costs are
included in this department’s expenses. Injuries and damages, and workers’
compensation expenses are also included in this area. Injuries and damages include
liabilities that arise in the normal course of business for various types of expense that
cover items such as compensation for damaged trees and crops, restoration of driveways,
lawns and fences, and accidents and lawsuits that are up to the $ 0.5 million insurance
deductible per occurrence.

Strategy and Portfolio Management provides strategic planning in support of
managing the Company’s gas assets.
Q. The third department within the Gas Division is the Customer Operations Department. Please provide a brief summary of the activities, excluding Uncollectible Write-Offs which will be addressed by Company witness Daniel L. Harry for that department.

A. The Customer Operations Department is responsible for the vast majority of all direct contact between the Company and its gas and electric customers, including customer inquiries, billing and payment, and customer preferences.

Q. What operating sections are included in the Customer Operations Department?

A. The Customer Operations Department is composed of the following six major sections:

- Customer Service
- Revenue Recovery
- Business Customer Operations & Strategy,
- Revenue Cycle Services
- Marketing, Energy Efficiency and Customer Research
- Business Support

Q. Please explain the functions of these six sections.

A. The Customer Service section is composed of the Call Centers and all the supporting areas required for their operation. The Company Call Centers are the first contact point between customers and the Company. The Call Centers handle all inquiries from residential and small commercial/industrial customers.

The Revenue Recovery section includes Credit and Collections, Direct Payment Offices (“DPOs”), Theft, Fraud, Consumer Affairs, Damage Claims and administrative activities related to Uncollectible Accounts. The Credit and Collections area handles customer accounts that are past due. Employees within this area make field stops to
customer premises in an attempt to collect past due money, sign customers up for low income programs or a payment plan where appropriate and/or disconnect service. The DPOs are walk-in customer payment offices in 13 locations around the state. The Theft area investigates reported theft tips from internal or external sources. The Fraud area investigates suspicious accounts where it appears that customers may be trying to avoid paying a previous bad debt. This area also investigates potential identity theft in compliance with the new Fair and Accurate Credit Transaction Act laws. The Consumer Affairs area attempts to resolve complex complaints forwarded to the Company by the Commission, Company management or legislators as well as other inquiries from within the Company. In addition, this area works with local/state and federal areas to collect payments on behalf of the customers to avoid disconnection.

The Business Customer Operations and Strategy section is responsible for meeting the informational and services needs of Consumers Energy’s largest and most complex business class customers. This section is composed of Business Customer Management and the Business Customer Operations Center. Business Customer Management includes Corporate Account Managers (“CAM”s) who deal directly with Consumers Energy’s most sophisticated business customers on energy issues affecting these customers. The Business Customer Operations Center, a specialized call center, is available to business customers during routine business hours and with extended hours during times of emergency situations.

The Revenue Cycle Services section is made up of Customer Billing. The Customer Billing area manages the exception billing process for Consumers Energy’s gas customers. “Exception billing” occurs when customer bills for some reason require
individual analysis in order resolve unusual billings, meter problems, etc. The exception process includes customer contact, billing adjustment, re-reading the meter, or billing as is. The Customer Billing area also includes Cashier and Control activities that include processing cash payments, managing customer security deposits and correcting Over/Short remittances.

The Marketing, Energy Efficiency and Customer Research section conducts several customer research studies that support the Company’s Customer Value Management program. These studies include surveys of various customer segments ranging from residential to large commercial and industrial which measure customer satisfaction with the products and services they receive for the price that they pay. This information is used to adjust our processes and develop communications that improve customer value. The section also markets value-added products and services such as the Appliance Service Plan and Carbon Monoxide (CO) Alarms and provides marketing support to core utility initiatives such as increasing enrollments in the Equal Monthly Payment Plan and soliciting contributions for People Care. The department also has responsibility for the implementation of the Company’s Energy Efficiency programs as required by 2008 PA 295. However, these expenses are not included in this case.

The Business Support section includes funding related to the use of envelopes, forms, service bill postage and IS&T software development and computer processing.

Q. Please explain the projected O&M expenses for Gas Customer Operations as displayed on Exhibit A-28 (DDH-2), line 3.

A. The projected O&M expenses for the 12 months ending September 2010 recognize increased administrative costs associated with credit and collections related to the rise in
uncollectable accounts, and theft and fraud areas in support of our LAUF loss improvement program which will be discussed later in my testimony.

Q. Please continue.

A. There are two components to the credit and collections O&M increase. First, due largely to the declining economic conditions in Michigan, the Company has hired additional staff to address the increases in occurrences of theft, fraud, credit and collection activity. The increased resources will mitigate additional financial losses in these areas and support our efforts to mitigate LAUF losses. Second, the Company is projecting increases in collection agency expenses in direct correlation to the increases projected relative to uncollectable accounts as found in Company witness Daniel L. Harry. As uncollectable accounts increase, collection agency costs associated with the recovery of our bad debt expense also increase.

Q. What level of projected O&M are you proposing in the credit and collection program?

A. The proposed increase to the credit and collection maintenance program is $1,622,000 as can be found on Exhibit A-29 (DDH-3), (line 4, column (b)).

Q. What is the projected duration of the proposed credit and collection program O&M expenses?

A. The proposed program and associated expenses would continue at this level into future years.
Q. The fourth department listed within the Gas Division is Gas Management Services, as can be found on Exhibit A-28 (DDH-2), (line 4). Please describe the primary functions within that department?

A. The Gas Management Services department, which is part of the Electric and Gas Supply Department, is a labor intensive department with responsibility for three major functions:

- Gas Control & System Planning
- Gas Supply / Strategic & Financial Planning
- Gas Transportation Services

The Gas Control & System Planning section is responsible to assure that adequate transmission and storage volumes and gas pipeline pressures are safely maintained on an instantaneous, daily and seasonal basis for deliveries made to over 150 city gates that supply the company’s natural gas distribution system. This section is also responsible for studying and projecting changes in transmission and storage system requirements and proposing system improvement recommendations.

The Gas Supply/Strategic & Financial Planning section is responsible for all gas supply and purchase functions, development of long-term and short-term gas supply strategies, risk management and gas supply related financial planning.

The Gas Transportation Services section manages gas nomination activity for all supplies entering the transmission and storage system. This section also manages the Gas Customer Choice program and all third party gas storage and transportation functions.
Q. The last department within the Gas Division is Gas Business Services. Please describe this department’s activities.

A. Operations conducted by this department include operations and maintenance for all Company gas related facilities work, real estate services for gas facility projects, and environmental and mail services for all general office locations. Facilities work includes items such as major equipment repair on heating, air conditioning and ventilation systems, other miscellaneous building repairs, yard maintenance and snow removal, daily cleaning or other major scheduled cleaning projects such as windows and carpeting. Real estate services includes the lease costs associated with our corporate facilities, records management costs for land transactions, and the cost of land management activities required to closely monitor encroachments onto the Company’s properties in order to ensure system integrity and safeguard the public. Mail services includes all activities relating to receiving, sorting, processing and delivering all mail for general office buildings which also includes all postage not related to gas billing.

Q. Does this complete your discussion of the Gas Division O&M Expenses requirements?

A. Yes.

Q. Please explain LAUF.

A. LAUF is the loss or gain of gas volumes as calculated by taking the difference between the volumes delivered into the transmission and distribution system and delivered out of those systems. Major causes of LAUF include gas leaks, measurement accuracy tolerances, customer billing issues, and gas vented for operational and maintenance of our system.
Q. Please describe the Lost and Unaccounted for Gas (LAUF) expenses that are expected during the 12 months ending September 2010.

A. The expenses related to LAUF remain based on a 5-year average of actual LAUF volumes, and the projected commodity cost of gas. Development of LAUF expenses can be found on Exhibit A-30 (DDH-4). As shown on that exhibit (line 1, column (c)), the test year projected LAUF expense level is $22,170,000.

Q. Please explain Exhibit A-30 (DDH-4).

A. This exhibit identifies the expected changes from the historical 2008 amount for LAUF to the test year period. The test year LAUF amount was calculated utilizing a methodology consistent with prior MPSC gas rate orders, updated with the most recent 5-year average Line Loss percentage and expected 2009 cost of gas expense as provided to me by Company witness David W. Howard. Additionally, this exhibit contains the Company Use Gas projected expenses for the test year. Company Use Gas will be discussed later in my testimony.

Q. Please explain Exhibit A-31 (DDH-5).

A. This exhibit calculates the most recent 5 year average Line Loss percentage, (line 6, column (e)), of 1.0844. This percentage, when applied to test year throughput levels, determines the expected LAUF volumes during the test year.

Q. Please explain Exhibit A-32 (DDH-6).

A. This exhibit calculates the expected test year amount of LAUF expense (line 14, column (f)) of $22,170,000, consistent with past MPSC methodology. The test year throughput level and the updated Line Loss percentage previously discussed have both been utilized to determine LAUF volumes and the associated expense levels. In addition, as shown on
line 11, the Allowance for Use and Losses percentage, also known as the In-Kind percentage, has been updated to reflect test year expectations.

Q. Is the level of LAUF expense the Company is requesting reasonable?

A. Yes. The MPSC has consistently utilized a 5-year average of Line Losses to set LAUF volumes and the Company’s presentation continues to utilize that same methodology, updated to reflect the most recent data. That line loss is based on actual losses on our gas transmission and distribution system over the past 5 years. It should be noted that the calculation of LAUF volumes in previous gas rate cases for the company utilized line loss data which actually contained a gain, not a loss, for purposes of calculating LAUF volumes. The Company’s customers enjoyed the benefits of lower gas rates as a result of this gain which has now expired within the five year average calculation.

Q. Why have you included the storage inventory losses of 420 MMcf associated with Ray and Northville Storage fields in your 2007 – 2008 LAUF figures?

A. This methodology is consistent with the MPSC Staff proposal in Case No. U-14547 for treatment of an inventory adjustment in that case which was approved by the Commission. In that case it was ruled that those volumes should be recovered over a 5 year period, within the LAUF calculations. I am proposing an identical approach be utilized in this proceeding for this latest inventory adjustment, related to the Ray and Northville Storage fields.

Q. Please explain the latest inventory adjustment related to the Ray and Northville Storage fields.

A. Gas losses due to storage deviations represent an adjustment to individual storage field inventories that true-up the volume and the value of the gas in storage based on a
calculation from pressure survey data for gas storage inventory verification. These
deviations can occur because of reservoir expansion/contraction, measurement
inaccuracies, and leakage through valves.

Q. Please describe the gas storage inventory verification process within Consumers Energy.

A. As a prudent operating practice, Consumers Energy does a storage field pressure survey
at each of its storage fields at the conclusion of every storage injection cycle (usually
September – October) and every withdrawal cycle (usually April – May). Storage well
pressures are collected and a calculation of the inventory in each storage field is
performed based on the pressure survey data. It was through this process that the
inventory balances at the Ray and Northville storage fields exhibited some abnormalities,
generating further analysis.

Q. Why is the performance of storage inventory verification a prudent practice?

A. The verification of the inventory in each storage field after each injection and withdrawal
cycle checks the integrity of the storage reservoir and confirms the inventory volume
based on the measurement volumes to/from storage for gas accounting purposes. Beyond
the integrity check, it also confirms the accuracy of the measurement, and whether the
valves are sealing tightly between the transmission and storage systems.

Q. What have been the recent results from the gas storage inventory verification process?

A. Beginning in the 2004 time frame the survey results for Ray and Northville fields started
deviating from the Accounting booked figures. The Company has confirmed that the
integrity of these storage reservoirs has not been compromised: that is, the rock strata
used for storing gas does not leak. However, the company has determined that several
valves and inaccurate orifice meters have allowed gas to flow from the storage field into
the transmission system that was not detected or measured. This has the impact of understating the volumes coming from storage and the resultant LAUF amounts. The Company policy for identifying a change in gas storage inventory is based on a two to three years of data to confirm the change due to the variations in the storage field operations from year to year that can cause pressure variances, resulting in the natural gas to migrate deeper into the rock formation and therefore impacting the survey results. As a result of this analysis, the Company has made downward adjustments to the inventory in the Ray and Northville fields to reflect the gas lost from inventory, which is 420,000 Mcf. Since the MPSC has previously opined on a similar issue in their order in Case No. U-14547, the Company is seeking the same regulatory treatment for this inventory adjustment in this filing.

Q. Why does the storage inventory deviation problem occur?
A. The majority of the present storage field measurement was done, until the past couple of years, with orifice plate meters. On injection, compressor pulsation affects the accuracy: on withdrawal, liquids and particulates affect the accuracy. Storage field meters and valves tend to be very old and may not perform as intended. In addition, orifice plates can also become bent and/or warped over time and can also develop rounded edges all of which affect their accuracy. The Company is nearly complete with a program to replace the existing orifice meters at its major storage field sites with ultrasonic meters, which should provide more accurate measurement. The Company will be done with this process by year end 2009.

Q. Have the orifice meters at Ray and Northville fields been replaced by ultrasonic meters?
A. Yes.
Q. Does more accurate measurement necessarily result in a reduction of LAUF volumes?

A. No. It can result in increased/reduced LAUF volumes as better measurement is achieved, depending on the particular location/situation.

Q. What steps has the Company undertaken to address the level of LAUF volumes?

A. As a result of rising gas prices and fluctuating LAUF volumes, the Company has undertaken a number of actions to address the level of LAUF volumes and its associated cost impacts. These actions to date are as follows:

- Installation of ultrasonic metering at high volume Company locations, particularly MCV and the storage fields.
- Purchase and installation of a new gas measurement system
- Creation of a Gas Measurement Group to address LAUF-related issues
- Increased field training
- Investigation of customer metering set-ups
- Enhanced and a more robust program for witnessing and inspecting the major components/instruments at the Company’s measurement stations.
- Enhanced theft investigation at retail customer locations.
- Creation and continuation of a Management Task Force addressing LAUF issues.

Q. What is the purpose of these actions?

A. The purpose of these actions is to ensure that the focus on LAUF continues and that the Company measurement, monitoring and practices associated with LAUF are consistent with industry best practices.
Q. What has been the Company’s experience since undertaking the increased emphasis on LAUF?

A. The LAUF for the calendar periods of 2007 and 2008 have both resulted in approximately 4,000 MMcf of line losses related to sales customers.

Q. Please describe the Company Use Gas Expenses.

A. These expenses are for the natural gas fuel used to run the compression and other equipment utilized on the transmission and storage system. The largest single use is for fueling the compressors and gas heaters at our city gate stations. The total cost of fuel gas used is reduced by credits received from transportation suppliers. These suppliers provide ‘gas-in-kind’ to Consumers Energy based on a percentage of their deliveries into the system.

Q. What level of expense for Company Use Gas are you proposing in this case?

A. As set forth on exhibit A-3 (DDH-4), (line 2, column (c)) the Company Use Gas expense for the 12 months ending September 2010 is projected to be is $7,556,000. The methodology used to derive this is identical to that used previously by the MPSC in setting gas rates. The calculation supporting this value can be found on my Exhibit A-32 (DDH-6).

Q. What is the Company projecting for LIEEF O&M expenses for the 12 months ending September 2010?

A. Exhibit A-27 (DDH-1), (line 4, column (c)) shows the amount of $17,427,000 for LIEEF for that period. This is the same amount approved by the Commission in the 2008 Gas Rate Order (MPSC Case No. U-15506).
Q. Are Uncollectable Write-off O&M expenses included in your testimony?
A. No. Uncollectable Write-offs are included in the testimony of Company witness Daniel L. Harry.

Q. Does this complete your testimony on the Gas Operations (excluding AMI) O&M expense requirements for the test year 12 months ending September 2010?
A. Yes.

Q. Are you sponsoring any capital exhibits?
A. Yes.

Q. Please describe the Company’s projections of capital expenditures for Gas Operations (excluding AMI).
A. As shown in Exhibit A-34 (DDH-8), the total Gas Operations capital expenditures for which the Company is requesting rates recognition in this case for the year 2009 and the 9 months ending September 2010 are $233,135,000 and $193,216,000 as set forth in this exhibit on (line 8, column (b)) and (line 8, column (c)), respectively. These projections are based upon activity levels required in the various programs to meet customer reliability, safety requirements and system demands. In addition to activity levels, the projections reflect capitalized cost increases such as wage and salary increases and commodity costs. For example, there has been a dramatic increase in the cost of materials used in construction in recent years and shortages in material supplies as infrastructure replacements have increased.

Q. Please list the major programs within the Gas Operations (excluding AMI) capital expenditures?
A. The major programs, as shown on Exhibit A-34 (DDH-8) lines 1 – 7 are:
Q. Please describe the capital expenditures related to the New Business program as shown on Exhibit A-34 (DDH-8), line 1.

A. The New Business program consists of the capital cost of adding new commercial, industrial and residential customers. The program costs include the cost of installing mains and services, and the cost of meters to service new customers. These costs are partially offset by customer contributions. We are projecting total New Business capital expenditures (net of customer contributions) to be $17,916,000 for the year 2009 (line 1, column (b)) and $13,236,000 for the 9 months ending September 2010 (line 1, column (c)).

Q. Please describe the capital expenditures related to the Asset Relocation program as shown on Exhibit A-34 (DDH-8), line 2.

A. The Asset Relocation program includes gas transmission and distribution infrastructure replacement projects which are required due to civic improvement activities initiated by federal, state, or local governmental units. Civic improvement includes projects to replace or improve aging public infrastructure such as roadways, bridges, sewer lines, water lines, and drainage ditches. All civic improvement projects are reviewed by our
preplanning staff. If our system is in the public right-of-way, and we have to move it to eliminate interference, it is done at our expense. We work with the governmental unit involved to coordinate work and negotiate design criteria wherever possible to minimize our expense. If necessary, asset relocation work could involve removing gas lines from bridges and removing and replacing gas lines to a new location. As shown on Exhibit A-34 (DDH-8), line 2 the capital expenditure projections for this program are $17,238,000 for the year 2009 (line 2, column (b)) and $17,237,000 for the 9 months ending September 2010 (line 2, column (c)). These projections are based upon past history, recent economic trends as well as knowledge of specific local projects planned for the next several years. For the test year 12 months ending September 2010 the increase is required to meet the projected level of asset relocations associated with local and state government “Stimulus Dollars” spending.

Q. Please describe the capital expenditures relating to the Regulatory Compliance program shown on Exhibit A-34 (DDH-8), line 3.

A. The Regulatory Compliance Program includes projects that are required to comply with federal pipeline safety regulations. These projects include the Meter Move-Out Project and other Meter Replacements, Pipeline Integrity, Cathodic Protection and Regulation projects. The capital expenditure projections for this program are $44,136,000 for the year 2009 (line 3, column (b)) and $36,020,000 for the 9 months ending September 2010 (line 3, column (c)). The changes in this program are based on normal economic pressures such as wages and material costs, and projects identified through system assessments. The Pipeline Integrity program expenditures change from year to year because of work scope variations, which are driven by assessments of threats and risk
translating to a priority-based inspection schedule, and the expected remediation costs resulting from the findings of these inspections. This program is performed in compliance with the federal Pipeline and Hazardous Materials Safety Administration requirements. Additional projects such as distribution pipeline augmentation and system regulation improvements were identified as necessary to ensure compliance with Maximum Allowable Operating Pressure regulations and are included in the program.

Q. Please describe the capital expenditures relating to the Material Condition program set forth on Exhibit A-34 (DDH-8), line 4.

A. As shown on Exhibit A-34 (DDH-8), the capital expenditure projections for this program are $29,622,000 for the year 2009 (line 4, column (b)) and $45,480,000 for the 9 months ending September 2010 (line 4, column (c)). The increases in this program for the 9 months ending September 2010 are due to reestablishing our material condition replacements in line with project decision analysis results, and restarting a program to replace remaining cast iron pipe.

Q. Please explain.

A. Approximately 630 miles (2.5%) of our distribution main miles are cast iron pipe. Installation of some of this pipe dates back to the 1880s. Because cast iron operates at low pressure, it is more susceptible to ground water infiltration and freeze-ups in winter as compared to more modern materials. The cast iron is located mainly in older neighborhoods, and freeze-offs can cause severe customer hardship. In recent years, freeze-ups of cast iron pipe have escalated and have led to considerable customer service interruptions. These customer service interruptions have been particularly frequent in the cities of Flint and Saginaw and have generated numerous customer complaints. Capital
expenditures of $18,000,000 are included the 9 months ending September 2010 figure to address this issue more aggressively by replacing approximately 25 miles of cast iron pipe and upgrade the distribution system associated with the pipe replacement to a higher operating pressure.

Q. Please describe the capital expenditures relating to the Capacity and Deliverability program as shown on Exhibit A-34 (DDH-8) line 5.

A. These capital expenditures reflect needed increases in transmission pipeline capacity, as well as storage and compression reliability, all intended to ensure adequate capacity and deliverability throughout the system. Capacity requirements increase due to shifts in population into new locations, as well as changes in system requirements such as the need to support load and maintain pressure (both base and peak day), as well as to provide capacity in order to inspect and remediate segments of pipe in the Pipeline Integrity program. Expenditures associated with many of the larger projects within this program can be found in Exhibit A-39 (DDH-13). In particular, these numbers reflect capital expenditures of $40,000,000 for the year 2009 and $511,000 for the 9 months ending September 2010 for capacity increases in the West Oakland Pipeline, Phase 2. Projections are based on a cost per mile for new pipeline of approximately $5.2 million. Costs are driven primarily by cost of pipe (approximately $1 million per mile), cost of valves (estimated $2.5 million total), and cost of labor. Skilled labor is in short supply as there are several pipeline projects west of the Mississippi that are currently attracting the majority of the skilled labor. This project received a Certificate of Necessity and Convenience, and Phase 1 was installed in 2005. This second phase will complete the construction required to provide peak day capacity to much of our system in Southeast
Michigan, where capacity constraints are increasing. Completion of West Oakland Phase 2 is also needed to take other transmission pipelines temporarily out of service for inspections and maintenance as required by the Pipeline Integrity program.

Q. Are there any other capacity and deliverability projects included in this program?
A. Another capacity and deliverability project included in this program is the Dewitt Pipeline Improvement project, projected at $1,000,000 for the year 2009 and $5,965,000 for the 9 months ending September 2010. This project was also issued a Certificate of Necessity and Convenience from the MPSC in February 2007. The project includes necessary upgrades to a 20” transmission pipeline and the associated city gate enhancement.

Q. What other projects are reflected in this program?
A. Another major project is the White Pigeon Compressor Station Improvement project. The projections reflect $49,498,000 for the year 2009 and $5,900,000 for the 9 months ending September 2010. Costs of new compression are based on projections for engines and compressor units between $3.5 million and $5 million depending on unit size. That projection then factors in cost of site preparation, piping changes and labor. Lead time for air permitting and engine availability is approximately 35 to 50 weeks. Nationwide, sales of new compressors are increasing rapidly as new pipelines require compression, and as engines are becoming obsolete from both age and repair part availability. This project will provide four additional units at White Pigeon to ensure that the station’s compression requirements are fulfilled in the future. White Pigeon is the largest system receipt point by volume on the Company’s Gas T&S system. This project will address an existing deficiency in compression availability. These compressors are over 35 years
old and replacement parts must now be reverse-engineered from old parts, as they are no longer available -- a process that is very costly and not always successful.

Q. What other projects are reflected in this program?

A. Another project is the Ray Compression Station Upgrade. The projections reflect $2,000,000 for the year 2009 and $41,604,000 for the 9 months ending September 2010. This project will provide five additional units to improve station reliability. With respect to serving gas customers throughout the winter heating season, Ray Storage Field is the most critical asset on the Company’s Gas T&S system. From a design perspective, Ray Storage Field is expected to provide over 50% of the total peak day storage field withdrawal capability and over 40% of the total system supply capability. This project will ensure that sufficient compression is available during the storage field injection cycle. This project is also the first of three phases designed to ultimately increase the cyclic capacity of the storage field itself.

Q. What other projects are reflected in this program?

A. Finally, there are capital investments projected at $3,900,000 for the year 2009 and $4,509,000 for the 9 months ending September 2010 for new wells, which are needed to maintain required deliverability from existing storage fields, as storage wells naturally deteriorate over time.

Q. Please describe the capital expenditures relating to the Gas Operations Other program as shown on Exhibit A-34 (DDH-8) line 6.

A. There are a number of areas that are contained in the Gas Operations Other program. These include computer and related equipment, software, right-of-way and tools. Capital expenditures in Gas Operations Other are projected at $3,428,000 for the year 2009
(line 6, column (b)) and $3,799,000 (line 6, column (c)) for the 9 months ending September 2010. A principal project in computer equipment and software relates to the replacement upgrades of work management servers and placement of work planning field devices in gas transmission and storage to improve work order management systems in this area. Additionally, a project to convert and upgrade the communication methodology of our gas transmission Supervisory Control and Data Acquisition (SCADA) system from an analog signal to a digital signal technology is included in these expenditures. It also includes security enhancements based on appropriate risk assessment methodology and prioritized investments in compliance with Transportation Security Administration standards.

Q. Please describe the capital expenditures relating to the Gas Business Services program as shown on Exhibit A-34 (DDH-8) line 7.

A. There are a number of areas that are contained in the Gas Business Services program. These include facilities investments, real estate records, transportation fleet investments and access control expenditures. Capital expenditures in Gas Business Services are projected at $15,165,000 (line 7, column (b)) for the year 2009 and $8,762,000 (line 7, column (c)) for the 9 months ending September 2010. A principal project to convert paper-based real estate property records to an electronic format is included in the projection. Principal decreases in asset preservation and access control reflect the completion of the Howell Service Center in 2009. This program also includes repairing failed capital components of buildings including yards and grounds, building envelope and operating systems; removing conditions that contribute to potential health and safety hazards; proactively repairing emergency backup systems, those minimal facilities
infrastructure investments which mitigate the effects of building depreciation to avoid imminent near term failures and upgrades for health and wellness. Additionally, it reflects replacing and/or maintaining the company's uninterrupted power supply system. This program also includes capital requirements to move to a levelized fleet replacement plan based on age and condition of vehicles.

Q. Does this conclude your testimony on the Gas Operations capital expenditures for the year 2009 and the 9 months ending September 2010?
A. Yes.

Q. Please describe the AMI Program.
A. The proposed AMI Program will consist of integrated systems that will measure, collect and analyze energy usage information. The system will include electric and gas meters capable of transmitting and receiving data ("smart meter"), a two-way communications network, a system to manage the data, enterprise/asset management software and a customer interface. An indicative schematic and a brief description of the main components are included as Exhibit A-44 (DDH-18).

Q. What is Consumers’ approach to AMI?
A. While the Company is anxious to make the benefits of AMI available to its customers as soon as possible, the Company has developed an implementation plan that mitigates the risk of deploying this relatively new technology as much as possible. By closely shadowing early adopters, we are gaining from the experiences of others before selecting final product and configuration. Significant time is required to thoroughly evaluate, develop and test the equipment and systems needed to implement AMI. The Company believes it is critical to implement a system to manage high volumes of meter data and
that a carefully thought-out secure integrated architectural structure is the first step in deploying AMI. Utilities who rushed to begin smart meter installations prior to system development have experienced significant issues and rework. Our recommended approach, which includes an AMI Technology, Systems & Deployment Pilot (AMI Pilot), mitigates these risks. It ensures we have the appropriate systems and architecture in place prior to field deployment, thereby minimizing adverse customer impacts.

Q. What is the timeframe for Consumers AMI Program?

A. Consumers AMI Program team has identified an AMI Pilot and implementation timeline of 2007-2015, as shown in Exhibit A-43 (DDH-17). The initial focus of the program involves the development of functional requirements and the identification of the commensurate enabling technology, including smart meters, two-way communications, data management, software application integration/functionality and customer interfaces. The program’s emphasis for the test year 12 months ending September 2010 will be the assessment, development and evaluation of systems and field equipment including a pilot of approximately six thousand smart meters which will include approximately four hundred pilot gas meters. Transition from the AMI Pilot to full-scale electric smart meter deployment and the addition of communication modules to existing gas meters is anticipated to commence in 2011 and be completed by 2015.

Q. How will Consumers’ gas customers benefit from an AMI Program?

A. An AMI Program can provide enhanced customer service and value through O&M effectiveness and efficiency improvements together with anticipated uncollectible accounts reductions. Benefits will become available to customers once the supporting systems and communications infrastructure are in place and as smart electric meters and
gas meter-modules are deployed across our service area. More information regarding how
customers can benefit from the implementation of AMI follows in my testimony.

Q. What O&M effectiveness and efficiency benefits can be enabled by an AMI Program?

A. The implementation of AMI will provide the opportunity to reduce operating costs and
improve our effectiveness in meeting customer needs. Billing accuracy will improve
with the availability of actual meter reads, reducing the number of monthly estimated
reads to less than 1 percent. Information including on-demand actual reads will be
available to respond to customer move-in/move out requests and address questions
concerning energy usage.

Q. How else can AMI reduce customer cost?

A. AMI can facilitate and accentuate energy efficiency and conservation by virtue of
enhanced ability for customers to identify savings opportunities and validate the
effectiveness of actions taken. Similarly, system losses due to factors such as theft and
other unidentified system losses are costs borne by all customers. It is anticipated that
these costs will be reduced by virtue of enhanced loss detection.

Q. Will the aforementioned benefits be quantified or evaluated further?

A. Yes. In conjunction with the AMI Pilot, which includes the continued evaluation of AMI
technology, systems and deployment including piloting SMART meters, evolving
industry best practices and/or anticipated Commission ordered guidance will continue to
be applied to directly measure or reasonably estimate, evaluate and refine the anticipated
costs and benefits of AMI technology, systems and deployment.
Q. What capital investments are expected in conjunction with the implementation of Consumers proposed AMI Program?

A. Based on current knowledge and discussions with various suppliers and vendors we currently believe that purchasing, testing, processing and installing smart meters and the enabling infrastructure will cost approximately $625,000,000 for Electric Operations and $230,000,000 for Gas Operations through 2015.

Q. How did the Company determine the allocation of common infrastructure and other shared expenditures for the AMI Program between the Company’s regulated gas operations and regulated electric operations?

A. The allocation of common infrastructure and other shared expenditures is approximately 72% Electric Delivery and 28% Gas Delivery. This allocation is based upon electric meter/communications/load management direct costs and gas module/communications direct costs.

Q. What AMI capital expenditures and O&M expenses is the Company seeking the Commission’s approval for in this case?

A. The Company is asking for Commission approval of AMI Program capital expenditures, which include cost for the AMI pilot, Architecture and Assessment and long lead development costs for systems and software for the year 2009 and the 9 months ending September 2010 of $8,097,000 and $22,894,000 as set forth on Exhibit A-34 (DDH-8) on (line 9, column (b)) and (line 9, column (c)), respectively. The Company is also asking the Commission to approve a test year O&M expense level of $854,000 which include costs for the AMI pilot, and AMI Program management. The O&M expenses related to
the AMI Program for the test year 12 months ending September 2010 are shown in Exhibit A-27 DDH-1, (line 6, column (c)).

Q. Does this conclude your testimony regarding the AMI Program O&M expenses and capital expenditures?

A. Yes, it does.

Q. Please summarize the total Gas Operations and AMI O&M expenses the Company is seeking the Commission’s approval for in this case?

A. The Company is asking for the Commission’s approval of $254,139,000 for Gas Operations and AMI O&M expenses as can be found in Exhibit A-27 (DDH-1), (line 7, column (c)).

Q. Please summarize the total Gas Operations and AMI capital expenditures the Company is seeking the Commission’s approval for in this case?

A. The Company is asking for the Commission’s approval of $241,232,000 for Gas Operations and AMI capital expenditures for year 2009 as can be found in Exhibit A-34 (DDH-8), (line 10, column (b)) and $216,110,000 for the 9 months ending September 2010 found in Exhibit A-34 (DDH-8) on (line 10, column (c)).

Q. Does this conclude your testimony?

A. Yes its does.
In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for the
distribution of natural gas and for other relief
Case No. U-15986

DIRECT TESTIMONY

OF

DAVID W. HOWARD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2009
DAVID W. HOWARD  
DIRECT TESTIMONY  

Q. Please state your name and business address.
A. My name is David W Howard. I am employed by Consumers Energy. My business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. What is your position with Consumers Energy?
A. I am the Director of Gas Supply.

Q. Would you briefly describe your background?
A. In 1980, I was graduated from Ferris State College with a Bachelor of Science Degree. In 1980, I joined Consumers Energy as an Auditor in the Internal Audit Department. In 1981, I transferred to the General Accounting Department and through 1989 held positions of increasing responsibility with respect to Corporate Accounting. In June 1989, I assumed the position of Fuel Supply Coordinator in the Gas Supply Department. In February 1992, I was promoted to Gas Supply Administrator. In October 1997, I assumed the position of Gas Acquisition Director of the Gas Supply Department. In April 2003, I assumed the position of the Director of Gas Supply.

Q. What are your responsibilities as Director of Gas Supply?
A. I am responsible for directing the Company’s efforts to obtain reliable and reasonably priced gas supply for its customers, and also responsible for the negotiation and administration of all gas supply and transportation contracts.

Q. Have you previously provided testimony before the Michigan Public Service Commission?
A. Yes. I filed testimony in various Gas Cost Recovery (GCR) plan and reconciliation cases. Most recently, I sponsored testimony on behalf of Consumers in its 2009/2010 GCR Plan proceeding Case No U-15704.
Q. What is the purpose of your testimony?
A. The purpose of my testimony is to provide gas pricing information that will be utilized to establish the 13-month average volume and cost of gas stored underground. In addition, I am providing the peak day design information that will be used in designing the Company’s proposed rates in this proceeding. Finally, I will address the level of Miscellaneous Revenue related to Buy/Sell and Asset Management Agreements (AMA) included in the Company’s presentation in this proceeding.

Q. Are you sponsoring any exhibits?
A. Yes. I am sponsoring the following exhibits:

   Exhibit A-45 (DWH-1) Storage Fields Month End Summary
   Exhibit A-46 (DWH-2) 2010 Peak Day Requirements
   Exhibit A-47 (DWH-3) Miscellaneous Revenue

Q. Were these exhibits prepared by you or under your supervision?
A. Yes.

GAS STORED UNDERGROUND

Q. Please describe Exhibit A-45 (DWH-1)
A. Exhibit A-45 (DWH-1) is a listing of the Company’s September 2007 through September 2010 underground gas storage volumes and dollars.

Q. Would you briefly explain the background for Exhibit A-45 (DWH-1)?
A. Yes. Exhibit A-45 (DWH-1) reflects the end of the month underground gas storage volumes and dollars which result from the Company’s natural gas purchases for its GCR and GCC customers. The costs and volumes reflect the Company’s existing supply and
transportation contracts for the historical period, as well as those of the GCC suppliers. Projected supply sources and prices are used for the future periods.

Q. What is the Company’s projected 2009 13-month average volume and cost of gas in storage as set forth on Exhibit A-45 (DWH-1)?


Q. What gas prices have you assumed for 2009 in developing your Exhibit A-45(DWH-1)?

A. I used the average NYMEX settlement prices for 2009 as of the first five business days of April. These NYMEX natural gas prices averaged $5.87/MMBtu for 2010. Using these prices, I calculated an average cost of gas sold through September 2010 of $7.528/Mcf.

PEAK DAY REQUIREMENTS

Q. Would you please describe Exhibit A-46 (DWH-2)?

A. Exhibit A-46 (DWH-2) sets forth the Company’s forecast of its 2010 Peak Day Requirements of 3,573 MMcf. It is based upon the assumption of an 80 Degree Day (-15 degrees Fahrenheit average for the day) weather occurrence on the system on January 31, 2010 and is the projected coldest day of the 2009-2010 heating season.

MISCELLANEOUS REVENUE

Q. Would you please explain Exhibit A-47 (DWH-3)?

A. Yes. Exhibit A-47 (DWH-3) contains the revenues achieved by the Company since 2003 for Buy/Sell and Asset Management Agreement (AMA) activity.
Q. Would you please describe Buy/Sell transactions?

A. Yes. In Buy/Sell transactions, natural gas volumes are purchased by the Company at a point in time at a specific price from a supplier. At the time of purchase Consumers Energy agrees to resell the subject gas back to that same supplier at an agreed price and time in the future. The difference between the purchase and sale price is the gross margin retained by the Company. The Company deducts the cost of fuel and the cost of money incurred from the gross amount received to arrive at the net revenue shown on Exhibit A-47 (DWH-3).

Q. Would you please explain Asset Management Agreements (AMA)?

A. Yes. AMA transactions (formerly Joint commodity Marketing Agreement (JCMA) transactions) are contractual agreements between the Company and various of its natural gas suppliers which essentially change the delivery point on the subject supply contract from the field zone (i.e. well head) to our city gate in combination with release by the Company to the supplier of the firm transportation capacity that would otherwise have been used by the Company to transport the gas to the city gate. These actions allow the supplier to retain title to both the natural gas and firm transportation and gives the supplier an opportunity to sell the original field zone delivery volumes to third parties. In return, Consumers Energy receives 50% of the revenue generated from such transactions. The volume of gas that is the subject of the AMA transaction is contemporaneously replaced in kind by the supplier at our city gate. The Company makes the replacement shipper (supplier) whole for the transportation costs so that the net cost for purchasing the supplies and transporting to the Company’s system are the same as originally negotiated.
This assures the Company that it obtains the suppliers it bargained for at the price agreed to while taking advantage of commercial opportunities along the interstate pipeline.

Q. What level of Buy/Sell and AMA revenues should be included in the 2009-2010 test period?

A. I am proposing that a simple average of the revenues achieved for the period 2003 through 2009 be utilized for Buy/Sell activity in the amount of $5.708 million as the projected revenues included in rates for the 2009-2010 period. I am proposing that a simple average of the revenues achieved for the period 2003 through 2008 be utilized for AMA activity in the amount of $4.635 million, as the projected revenues included in the rates for the 2009-2010 period.

Q. Why are you proposing the use of a historical simple average?

A. These revenues are subject to market conditions. It is impossible to project what price level the natural gas market will achieve in the future and what price spread will be in place at the time a Buy/Sell or AMA transaction is entered into. I believe using a historical simple average fairly captures the market, weather and pricing anomalies that can and do occur and best reflects the projected level of revenue that may be achieved for this type of activity in the future.

Q. Does that conclude your direct testimony?

A. Yes, it does.
S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for the
distribution of natural gas and for other relief

Case No. U-15986

DIRECT TESTIMONY

OF

GARY L. KELTERBORN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business.
A. Gary L. Kelterborn, 1945 West Parnall Road, Jackson, Michigan.

Q. By whom are you employed?
A. Consumers Energy Company (Consumers Energy).

Q. What is your position at Consumers Energy?
A. I am Director of Remediation Management.

Q. How long have you been employed by Consumers Energy?
A. Since 1979.

Q. Please state your educational background and work experience.
A. I graduated from Michigan State University in 1979 with a Bachelors of Science Degree in Biochemistry. In January of 1996 I received a Juris Doctor Degree from Thomas M. Cooley Law School. My work experience includes a variety of technical and environmental responsibilities for the Company. I began working for the Company in 1979 as a project chemist in the Company’s Laboratory. From 1979-1983, I worked on operational and environmental projects, including, for example: conducting environmental studies in support of discharge permits for operating power plants and leading the analytical efforts to demonstrate compliance with permit requirements. In 1984, I was named Department Head of the Analytical Laboratory. In that role I redirected the laboratory’s focus from principally operations support to environmental compliance work, including the acceptance and completion of environmental projects from entities outside of Consumers Energy. During that period, the lab supported remediation of landfills, underground storage tank sites and industrial releases. In 1997, I was named Director of Remediation Management.
Q. What are your responsibilities in your present position?

A. As Director of Remediation Management, I am responsible for planning, directing and controlling the investigation and remediation of former manufactured gas plant (MGP) sites and Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) sites where Consumers Energy is a responsible party. My section also provides technical assistance to the gas and electric operating departments of Consumers Energy regarding the investigation and remediation of other sites of environmental contamination, such as other Michigan Natural Resource and Environmental Protection Act (Part 201) sites and certain leaking underground storage tank sites. I am also responsible for conducting environmental due diligence assessments for the acquisition, sale, lease and licensing of Consumers Energy property, and for the coordination of corporate PCB management programs.

Q. Are you a member of any professional societies or organizations?

A. Yes. I represent Consumers Energy on several environmental work groups, including Sediment Management Work Group. I am a member of the American Bar Association and the State Bar of Michigan. I am also a member of the Michigan Manufacturer’s Association, Part 201 Program Advisory Group, which consists of industry groups, environmental advocates, municipal governments, lenders and developers, advising the Department of Environmental Quality (DEQ) on technical, regulatory, legislative and policy issues relating to contaminated sites.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (i) identify the former MGP sites at which Consumers Energy has a present or former ownership interest, (ii) discuss environmental
requirements for investigation and remediation of Consumers Energy’s former MGP sites, (iii) identify and describe expenditures for environmental response activities at these former MGP sites that the Company is seeking approval to recover in this case, and (iv) address the prudence of these expenditures.

Q. Are you sponsoring any exhibits?
A. Yes. I am sponsoring the following exhibits:

   Exhibit A-48 (GLK-1) Manufactured Gas Plant Sites Information
   Exhibit A-49 (GLK-2) MGP Environmental Response Cash Outflows for July 2008-2009 by Site and Total
   Exhibit A-50 (GLK-3) MGP Environmental Response Cash Outflows for July 2008-2009 by Phase

Q. Were these exhibits prepared by you or under your supervision?
A. Yes.

Q. Please summarize your testimony.
A. Consumers Energy has identified 23 sites that formerly housed manufactured gas plants at which it has a present or former ownership interest. There is significant risk that reasonable and typical industry practices during the MGP era has resulted in environmental contamination that is unacceptable under current environmental standards and laws. Consumers Energy has incurred and will continue to incur costs related to investigation and remediation of MGP sites. Costs related to investigation and remediation of MGP sites that Consumers Energy is seeking approval of in this case will total approximately $6.1 million. These costs are reasonable and prudent.
Q. How is your testimony organized?

A. In Section 1 of my testimony I will identify and provide information regarding the sites Consumers Energy has identified where it has a present or former ownership interest. In Section 2 of my testimony I will discuss the reasons that Consumers Energy is undertaking environmental investigation and remediation activities at these sites. In Section 3 of my testimony I will discuss investigation and remediation costs at these sites. In Section 4 of my testimony I will address the prudence of those costs. The accounting and ratemaking treatment of the costs which I identify will be discussed by Company witness Daniel L. Harry.

SECTION 1

Q. How many MGP sites has Consumers Energy identified where it has a present or former ownership interest?

A. Consumers Energy has identified 23 sites that formerly housed manufactured gas plants at which it has a present or former ownership interest. These sites are listed on Exhibit A-48 (GLK-1). Gas was manufactured from these locations for various periods during the late 1800’s until the 1950’s when the last MGP was retired. The 23 sites were acquired or built by Consumers Energy between 1917 and 1934. Predecessor companies were either acquired by Consumers Energy or no longer exist.

Q. Please describe Exhibit A-48 (GLK-1).

A. Exhibit A-48 (GLK-1) provides a summary of site information for each of the 23 former MGP sites, listing location, approximate size of the site in acres, estimated peak plant capacity, date the plant was acquired or built by Consumers, date natural gas arrived, date
put on standby status, when the plant was retired, and when the holder (the MGP storage tank) was retired.

Q. What was the role of manufactured gas plants?

A. Manufactured gas plants were formerly an integral part of gas utility service. Prior to the availability of natural gas, gas was manufactured. As natural gas became available, it replaced manufactured gas as a base fuel. However, even after natural gas became available, maintaining the ability to manufacture gas on a stand-by basis was viewed as important. At most of Consumers Energy’s sites, after natural gas replaced manufactured gas, the plants retained their ability to manufacture gas for use in the event of gas shortages. In addition, the MGP storage tanks, often referred to as holders, were used to store natural gas.

SECTION 2

Q. Why is Consumers Energy undertaking environmental investigation and remediation activities at former MGP sites?

A. The level of environmental awareness has increased significantly since the time when MGPs were operated. The manufacture of gas resulted in various by-products which are now recognized as being environmentally harmful. Consumers Energy has discovered soil and water contamination at all 23 of the former MGP sites during remedial investigations. Under current environmental standards, Consumers Energy will incur clean-up costs at all of the sites.

The costs of environmental investigation and remediation with respect to former MGP sites are necessary and ongoing costs of doing business which were not, and could not have been, anticipated during the time MGPs were in operation. Awareness of the
environmental risk associated with these by-products did not exist during the MGP era. The costs of investigation and remediation are prudent expenditures and are based on public policy considerations of protecting the environment and natural resources of the State. These costs are unavoidable, are based on public policy considerations, and do not arise out of any failure to meet standards at the time the plants were in operation.

Q. How will site remediation requirements be determined for the former manufactured gas plant sites in Michigan?

A. The overall framework for environmental response activities is provided by several statutory enactments. In 1980 Congress enacted the Comprehensive Environmental Response, Compensation and Liability Act, commonly referred to as “Superfund”, which required potentially responsible parties to investigate and remediate various wastes. In 1982 the Michigan Environmental Response Act (Act 307) was enacted. In 1990 the State of Michigan passed amendments to Act 307, which established a state program similar to the federal Superfund law, although broader in scope. In 1994 additional amendments were made and the Act was recodified as Part 201 of the Michigan Natural Resources and Environmental Protection Act (NREPA), MCL 324.20101 et seq. Part 201 provides the primary framework for investigation and remediation of Consumers Energy’s former MGP sites. The Department of Environmental Quality (DEQ) oversees Michigan’s Part 201 program. I am the Company’s primary interface with the DEQ on Part 201 issues.

Q. Who are responsible parties under Part 201?

A. Under Part 201 those liable for response activity costs include (i) the owner or operator of a facility if the owner or operator is responsible for an activity causing a release or threat
of release and (ii) the owner or operator of a facility at the time of disposal of a hazardous
substance if the owner or operator is responsible for an activity causing a release or threat
of release. Under certain circumstances others can also be liable for response activity
costs.

A party may be liable Under Part 201 even though the act causing environmental
contamination was lawful and reasonable at the time. Any potentially responsible party
may be held liable for the entire cost for investigation and remediation of a site. Part 201
states that it applies regardless of whether the release or threat of release of a hazardous
substance occurred before or after the effective date of Part 201.

Q. What is a utility’s responsibility at a former MGP site that it owned or operated?

A. Part 201 requires that when a current owner or operator of a facility obtains information
that there may be a release of a hazardous substance at a facility for which they are liable,
such owner or operator must take appropriate action, including confirming the existence
of the release, determining the nature and extent of the release, reporting the release to
the DEQ if there was a reportable quantity released and immediately taking steps to stop
any continuing release. Part 201 contains affirmative obligations to avoid exacerbation
of any existing contamination. The liable owner or operator must “diligently pursue”
environmental response activities including investigation and remediation and ultimately
address all contaminants associated with the site. Consumers Energy is the current owner
or operator of all or portions of most of the former MGP sites listed on Exhibit A-48
(GLK-1).

The DEQ has responsibility to oversee and coordinate all activities required under
the Act. The DEQ is authorized by Part 201 to request or order remediation by one or
more responsible parties or to undertake response activities and to recover costs incurred
from responsible parties later. Each year the DEQ publishes its List of Michigan Sites of
Environmental Contamination (Part 201 List). There are currently about 3,200 sites of
environmental contamination listed on the Part 201 List. At present 17 of the 23
Consumers Energy former MGP sites are listed on the Part 201 List. These are the sites
at Bay City, Charlotte, Flint (Court Street), Flint (East Street), Grand Ledge, Hastings,
Jackson, Ionia, Kalamazoo, Lansing, Manistee, Marshall, Royal Oak, Saginaw, Sault Ste.
Marie, St. Johns and Zilwaukee.

Q. Does a site have to be listed on the Part 201 list in order for an owner or operator to be
obligated to undertake environmental response activities or to incur response costs?
A. No. The DEQ is authorized to request that environmental response activities be
undertaken by a responsible party even if the site is not listed on the Part 201 list. In
addition, discovery of contamination at or near a former MGP site can require an owner
or operator to undertake response activities.

SECTION 3

Q. What levels of expenditures are attributable to environmental response activities at the 23
former MGP sites?
A. The level of expenditures for the period July 2008 through 2009 totals approximately
$6.1 million.

Q. Do these amounts include Project Management costs?
A. No. As recommended by Staff in case number U-14547, the Company has excluded
Project Management and associated costs from the MGP Environmental Response Cash
Outflows.
Q. Please describe what type of costs were excluded under Project Management and associated costs.

A. These costs include cost of Consumers Energy employees and associated expenses such as Labor, Lab Services, Fleet, Real Estate, business expenses and computer charges.

Q. What are the environmental response activity costs by year for July 2008 and 2009?

A. The costs by year are summarized on Exhibit A-49 (GLK-2), page 6.

Q. What were the environmental response activity costs for January through June 2008?

A. The 2008 costs for environmental response activities for the period of January through June totaled $1.2 million. These costs were reviewed and found to be reasonable by the MPSC Staff in Case No. U-15190 and therefore have not been included on these exhibits in the current case. The actual total costs for 2008 including the January through June costs in addition to the June through December costs were $3.1 million. These costs were all prudently incurred.

Q. What accounts for the variation in annual levels of expenditures?

A. The variation is due to the nature and level of the response activities. As I will discuss later in my testimony, remedial activities can be divided into phases. The variation in expenditures reflects the progression at the various sites from remedial investigations to interim response activities and then to feasibility studies and remedial action.

Q. At how many of the sites will Consumers Energy incur costs during the period July 2008 through 2009?

A. Costs will be incurred at all 23 sites.
Q. Please identify Exhibit A-49 (GLK-2).

A. Exhibit A-49 (GLK-2) shows the cash outflow for environmental investigation and remediation during the period July 2008 through 2009 for each MGP site. Costs are shown in total and by type of activity. The costs are also shown in total for the 23 MGP sites.

Q. How were these costs developed?

A. Costs for July through December 2008 of $1.9 million are actual costs incurred. Costs for 2009 include a combination of actual and projected costs. Costs which have not yet been incurred are based on the specific activities that will be undertaken at each of the sites.

Q. Why are the costs incurred different at different sites?

A. Costs for investigation and remediation are influenced by a number of site-specific factors. Costs can vary significantly depending on the nature and extent of contamination, size of the site, geology of the site, presence of surface water and depth of ground water, present and future use of the site, and types of remedial action. The costs on the exhibit are different due to these site-specific factors.

Q. Should these costs be considered known costs which can be measured?

A. Yes. As a result of the site investigations, there is at present extensive information concerning the extent of contamination at the 23 former MGP sites. Costs for July through December 2008 are actual and incurred. Costs for 2009 are based upon site-specific information and the activities that will occur at each of the 23 sites. These costs are based on detailed information and evaluation and have been determined by site and activity. Now that remedial investigations have been completed at all 23 sites and
interim responses and/or feasibility studies are underway at most of the sites, the Company has more complete information available than it did in the past.

Q. Will MGP environmental response activity costs be incurred beyond 2009?
A. Yes. The Company expects to incur additional environmental response costs beyond 2009.

Q. Could future costs be greater than you are currently estimating?
A. Yes. Costs are currently estimated based on cleanup to industrial criteria. If the DEQ or present site owners require clean up to residential levels, costs would be greater. Additional costs would also be incurred if:

1. Acquisition of deed restrictions from present owners is required.
2. Removal of contaminants from deep aquifers proves difficult.
3. DEQ seeks reopeners based on changing groundwater/surface water interface criteria.
4. Natural resource damages are sought against Consumers Energy.
5. The DEQ concludes that other or additional response activities are necessary.

SECTION 4

Q. What types of environmental response activities may be required at a former MGP site?
A. The sequence, timing and magnitude of response activities may vary from site to site depending upon the size of the site, the degree of environmental contamination, current land use, the degree of enforcement discretion exercised by DEQ, and other site-specific factors. However, the usual sequence of environmental response activities which would typically be undertaken at a former MGP site would be:
1. Site Investigation
2. Remedial Investigation
3. Interim Response
4. Feasibility Study
5. Remedial Action

Q. Please briefly describe each of these activities.

A. Site Investigation. A Site Investigation involves research of site related information such as available historical records, past and current site uses, topographical maps, engineering drawings and a review of potential sources of environmental contamination. A site visit is also usually done during a Site Investigation to relate the information collected by the records search to current site conditions and to conduct a visual inspection for any obvious signs of MGP contamination.

Remedial Investigation. The purpose of a Remedial Investigation is to define the nature and extent of contamination at a site. Consumers Energy has worked with the DEQ to reach a common understanding on facility prioritization criteria as it relates to risk assessment and exposure pathways. In addition Consumers Energy has sought input, review, and concurrence from the DEQ of work plans. This interactive approach has allowed Consumers Energy to be better responsive to DEQ concerns and issues in developing and implementing work plans. Remedial Investigations determine the extent of contaminate impacts onsite and offsite.

The Remedial Investigation includes the collection and analysis of samples of surface soils, subsurface soils and groundwater. Limited field screening measurements of soil,
gas and air samples may also be conducted. These samples are analyzed for chemicals of concern that are typical of MGP by-products and wastes.

**Interim Response Activities.** Interim Response Activities may be required if the results of the Remedial Investigation or other information indicates a need to abate a threat to human health or to the environment on an interim basis while further investigation occurs. Examples of the types of Interim Response Activities which may occur for contaminated soils include erecting a fence, installing drainage controls and stabilization, capping, removal, treatment or disposal of the contaminated soils to eliminate direct contact hazards and to prevent further migration.

**Feasibility Study.** The purpose of the feasibility study is to develop, evaluate and select which of several remedial action alternatives, including no action, may be appropriate.

**Remedial Action.** Remedial Action includes, but is not limited to clean-up, removal, containment, isolation, destruction or treatment of a hazardous substance released or threatened to be released. If Remedial Action is required, a Remedial Action Plan will be developed and implemented. The Remedial Action Plan will describe how the remedial action will comply with the requirements of Part 201 and how performance of the remedy will be measured.

Q. What is the current status of the 23 sites?

A. By the end of 1998 site investigations had been completed at all 23 sites. By June 2007 remedial investigations were completed at all sites. Interim response activities, where required, are well underway. Feasibility studies began in 2001 and have been completed at many sites. Upon completion of the studies, specific remedial scenarios are identified.
after negotiation with the DEQ. Execution of specific remedial scenarios at the sites began in 2003. Some remedial activities will continue for many years.

Q. Please identify Exhibit A-50 (GLK-3).

A. Exhibit A-50 (GLK-3) shows July 2008 through 2009 costs for each phase by site and year. This exhibit contains the same information as Exhibit A-49 (GLK-2) but organizes the information in a different fashion.

Q. Are the expenditures that you are seeking recovery for in this case reasonable and prudent?

A. Yes. The need for environmental investigation and remediation and the parameters for clean-up are mandated and defined by the state and federal government. The costs of investigation and remediation are not based on any imprudence, but upon public policy considerations of protecting the environment and natural resources of the State. MGP site investigation and remediation costs are legitimate and necessary costs of doing business. The costs incurred were costs for activities that are necessary under current environmental regulations. The need for incurring such costs is based upon current environmental awareness, not any fault on the part of the operator of the MGP facilities.

Consumers Energy has taken a proactive role with the DEQ. By taking a proactive role with the DEQ, Consumers Energy has a better opportunity to participate in decisions involving investigation and remedial actions than if the DEQ were to order remediation or to undertake remediation itself. Consumers Energy has undertaken, and will continue to undertake, investigation, response, and remediation activities in an efficient manner to seek to minimize costs consistent with health and safety considerations. Consumers Energy will seek approval from the DEQ of the most cost-
effective remediations which are protective of human health and the environment as allowed by law.

Q. Does the Company use competitive bidding as a means of controlling costs?
A. Yes. Current Company policies require competitive bidding for purchases of materials and/or services over $10,000, except for emergencies or where only one vendor can supply the goods or services. If competitive bids are not sought, the Company documents reasons why the competitive bidding process was not used. During the competitive bidding process the qualifications of each contractor and subcontractor will be reviewed to determine if they have the resources and expertise to complete the tasks on which they are bidding.

Q. Please describe how the consultants used were selected.
A. The main consultants for each site were selected using a bidding process. Consultants who were interested bid for each MGP site separately. As part of the competitive bidding process the qualifications of each contractor were reviewed to determine if they had the resources and expertise to complete the projects on which they were bidding. The Company selected 5 main consultants for the 23 sites. Using the same consultant for more than one site increases efficiencies. Limiting the consultants to less than all sites helps assure that they will be able to complete the work in a timely fashion.

Q. Please discuss interim response activities in July 2008 through 2009.
A. As noted previously, interim response may be required if the results of the remedial investigation or other information indicates a need to abate a threat to human health or environment on an interim basis. Interim response costs were incurred during July through December 2008 at 12 MGP sites. Interim response activity costs at 16 sites are
included in 2009. Interim response plans are discussed with the Department of Environmental Quality. The activities for these site specific work plans generally involve removing and disposing of soil which contained compounds exceeding the DEQ’s direct contact criteria and associated activities. In some instances interim response activities have involved removing groundwater containing chemical levels in excess of applicable criteria. Costs for interim response activities are shown by site and year on page 2 of Exhibit A-50 (GLK-3).

Q. Were subcontractors utilized for interim response activities?
A. Yes. The subcontractor work is competitively bid.

Q. Are the costs you have identified for interim response activities reasonable and prudent?
A. Yes. These costs were necessitated by the current level of environmental awareness and statutory provisions. The level of costs are reasonable and prudent given the nature of the required interim response activities.

Q. Please discuss feasibility studies in July 2008 through 2009.
A. As noted previously, the purpose of a feasibility study is to develop, evaluate and select which of several remedial action alternatives may be appropriate. In July through December 2008, feasibility study costs were incurred at 10 sites. Feasibility study costs for one site are included in 2009. Ultimately a remedial action plan for each site will be prepared for DEQ approval and implemented. The feasibility study costs shown on my exhibit are reasonable and prudent costs.

Q. Please discuss the costs for remedial action.
A. Remedial action costs began in 2003 with the collection of data supporting remedial action. The remedial action costs incurred prior to Remedial Action Plan negotiation and
approval are of two types: initiation of long term groundwater monitoring which is required in all contaminant remediation projects; and for field pilot tests the data from which is required to be included in the Remedial Action Plan in order to have the DEQ approve it. Activities in support of certain remedial alternatives, such as installation of equipment for field tests of proposed remedial activities, property purchases to support certain remedial alternatives, and groundwater monitoring continue through 2009. Remedial action costs are included for 23 sites in 2008 and for 20 sites in 2009.

Q. Are the cost levels shown for remedial action reasonable and prudent?

A. Yes. The levels of costs shown are reasonable and prudent.

Q. Is Consumers Energy seeking a prudence determination of July 2008 through 2009 costs in this proceeding?

A. Yes. The Company is seeking a determination of the prudence of costs for July 2008 through 2009. By the time this case is decided the 2008 and 2009 costs will have been incurred. The nature and extent of 2008 and 2009 activities and associated costs can be determined with reasonable certainty at this time and the prudence of those activities and costs can be reviewed. There is no need to defer consideration of the prudence of those expenditures.

Q. How did you determine the costs for each of the activities that have not yet occurred?

A. The cost for each activity is based upon the specific activity and was developed based on past experience at Consumers Energy sites and other sites, my overall knowledge, background and experience, consultant bids, and discussions with consultants involved with each of these sites.
Q. Has Consumers Energy identified any former MGP owners or any predecessor or successor companies of such owners for the 23 sites at which Consumers Energy has a present or former ownership interest?

A. No. A search for former MGP owners or any predecessors or successor companies of such owners for the 23 sites did not find any in existence today.

Q. Please summarize your testimony.

A. Consumers Energy has shown that the costs for environmental investigation and remediation during July 2008 through 2009 at the 23 former MGP sites are reasonable and prudent costs. Company witness Daniel L. Harry will identify the amortization expense that will occur as a result of these expenditures and the unamortized balance that Consumers Energy seeks to have included in rate base.

Q. Does this conclude your testimony?

A. Yes.
S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
CONSUMERS ENERGY COMPANY
for authority to increase its rates for the
distribution of natural gas and for other relief

Case No. U-15986

DIRECT TESTIMONY

OF

HERBERT B. KOPS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2009
Q. Please state your name and business address.
A. Herbert B. Kops, One Energy Plaza, Jackson, Michigan.

Q. By who are you employed?
A. Consumers Energy Company.

Q. What is your current position with Consumers Energy?
A. I am currently the Director of Employee Benefits.

Q. What are your responsibilities as Director of Employee Benefits?
A. I am responsible for design, implementation and administration of the Company’s retirement benefit and insurance benefit plans for employees and retirees. I also have responsibility for administration of the Company’s self-insured workers compensation program and the relocation plan.

In the retirement benefits area, the Company contributes to the cost of the Pension Plan, the Defined Company Contribution Plan (DCCP) and the 401(k) Savings Plan. My responsibilities for these benefit plans include the design and implementation of competitive, cost-effective, quality plans that will attract and retain qualified employees to serve customers. These plans are designed to provide a portion of an employee’s retirement income along with the employee’s social security benefits and personal savings.

In the insurance benefits area, the Company contributes to the cost of three primary insurance benefits plans - health care (medical/prescription drug/dental), life insurance, and long-term disability (LTD) insurance. Like the retirement plans, my responsibilities for these insurance benefit plans include the design and implementation of competitive, cost-effective, quality plans for employees and retirees of the Company.
that help attract and retain qualified employees to serve customers. In addition to these plans, I have responsibility for several additional benefit plans offered to employees by the Company at group discounted rates, which require the employee to pay the full cost of the coverage elected. These voluntary plans include 24-hour accident insurance, health care and dependent care flexible spending accounts, vision insurance, dependents term life insurance and long-term care insurance. These insurance benefit plans also help attract and retain qualified employees to serve customers as these plans help protect employees and their families from significant financial loss in a number of areas.

Q. What is your formal educational experience?

A. I graduated from the University of Michigan in Ann Arbor in 1977 with a Bachelor of Business Administration Degree. In 1987, I graduated from the University of Michigan – Flint, earning a Master of Business Administration Degree with High Distinction. Since joining Consumers Energy’s insurance benefits area in 1989, I have successfully completed a number of benefits certification courses through World at Work (formerly American Compensation Association) and obtained a Certificate in Benefits Administration.

Q. Would you please describe your previous work experience?

A. On May 23, 1977, I began my career at Consumers Power Company as a Human Resources Advisor in the Grand Rapids Service Center. In 1979, I accepted additional responsibility as the Human Resources Administrator in the Company’s Cadillac District. This was a generalist Human Resources role, offering independent work responsibility for 150 employees in the Cadillac, Prudenville, Clare and Big Rapids energy distribution headquarters.
In 1982, I became the Human Resources Supervisor in the Company’s Saginaw office of the Central Region. I supervised the Saginaw office operation staff in this generalist role and provided leadership and support to other Central Region offices as needed. My responsibility in Saginaw covered human resources responsibilities for over 600 employees in the Region.

I became the Insurance Benefits Supervisor for the Company in 1989 and moved to the corporate office in Jackson. In 1994, I became the Director of Insurance Benefits with responsibility for health care, other insurance programs and the relocation plan of the Company for all active and retired employees. In June of 2003, I became the Director of Employee Benefits for the Company and assumed responsibility for the retirement benefits plans (pension, defined company contribution and savings plans) and the workers compensation program.

Q. Are you a member of any professional societies or trade associations?

A. Yes, I am a member of World at Work. World at Work is an international professional association dedicated to knowledge leadership in compensation, benefits and total rewards. The concept of total rewards recognizes that the work experience includes factors that are important to employees in addition to compensation and benefits. I am also a member of the International Foundation for Employee Benefits.

I am a current member of the Michigan Chamber of Commerce Health and Human Resources Committee, having chaired this committee for a two year period during my membership. This Committee deals with health and human resources policy and legislation in the State from a business prospective. I am also currently on the Board of Directors for the Michigan Purchasers Health Alliance (MichPHA). This Alliance is
an association of employers in southeast Michigan that collaborate to improve health care quality and control health care cost among member companies.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to provide support for the Company’s gas costs related to the pension, defined company contribution, savings, health care, life insurance and long-term disability insurance (LTD) plans provided to its active employees and retirees.

Q. Are you sponsoring any exhibits?

Q. Please describe Exhibit A-51 (HBK-1).
A. Exhibit A-51 (HBK-1) summarizes 2008-2009 and the 12 months ending September 2010 gas operating and maintenance (O&M) expenses for the Company’s retirement and insurance benefit plans offered to employees and retirees. On this Exhibit, column (a) provides a program description of the O&M expense category. Column (b) provides the 2008 actual expense for each plan. Column (c) provides the projected expense in 2009 for each plan. Column (d) provides the projected expense for the 12 months ending September 2010 for each plan. Column (e) provides a source reference for the expense.

Q. Which retirement benefits are you addressing?
A. I am addressing the Pension Plan, Defined Company Contribution Plan (DCCP) and 401(k) Savings Plan. These expenses are shown on Line 1, 2, and 3 of Exhibit A-51 (HBK-1)
Q. How are Pension Plan, Defined Company Contribution Plan (DCCP) and 401(k) Savings Plan expenses that are common to gas and electric operations allocated to the gas portion of the business?

A. Expenses common to both the gas and electric operations associated with the Pension Plan, DCCP and Savings Plan are allocated on the basis of the relationship of employee labor dollars charged to gas operations compared to the labor dollars charged in both gas and electric operations. These allocations are made by the Accounting Department. The gas portion of the O&M expense for these plans is shown on Exhibit A-51 (HBK-1).

**Pension Plan**

Q. Would you please explain line 1 of your Exhibit A-51 (HBK-1), Summary of Benefits O&M Expense for the Years 2008-2009 and 12 Months Ended September 2010 – Gas Portion, which begins with $24,931,000 in 2008?

A. Exhibit A-51 (HBK-1) shows the actual 2008 pension expense and the projected pension expense for 2009 and the 12 months ending September 2010. These expenses are shown before any adjustments are made due to the Pension Equalization Mechanism (or pension tracker). Line 1 represents the operating and maintenance (O&M) expense associated with the Company’s Pension Plan attributable to the gas portion of the utility operations.

Q. How does the Company determine its expense for the Pension Plan?

A. The expense is determined using actuarial analysis that is performed in accordance with Statement of Financial Accounting Standards (FAS) 87. Consumers Energy follows Generally Accepted Accounting Principles (GAAP) for its financial statements. Under the provisions of GAAP, FAS 87 describes the methodology and assumptions required to properly calculate and account for pension expense. The calculations required by the...
accounting standards are performed annually by Consumers Energy’s actuary, Hewitt Associates. In addition, the actuarial assumptions are reviewed by the Company’s auditors to insure consistency with GAAP.

FAS 87 requires an annual determination of pension expense. Expense is determined based on actuarially reviewed employee census data, the plan provisions, plan assets and certain other actuarial assumptions. Year-end disclosure information is also produced, based on these accounting standards, to show a reconciliation of plan assets and liabilities at the end of the Company’s fiscal year.

Q. What are the components of the annual pension expense under FAS 87?

A. There are four components of the expense: (1) service cost; (2) interest cost; (3) expected earnings on plan assets; and (4) amortization of gains or losses, prior service cost and any transitional amounts. The plan’s service cost represents the value of the benefits earned during the year. This is determined individually for each participant based on his/her specific employee demographics. The interest cost represents interest on the plan’s liabilities due to the passage of time. All future benefits are discounted back to the valuation date based on an interest (discount) rate assumption. The discount rate used reflects the economic conditions at the time the expense is being determined. There is also an assumption made on the expected earnings of plan assets. The expected earnings on plan assets each year reduce the plan’s annual expense. The expected earnings assumption is reviewed periodically by the plan’s actuary and the Company and is intended to be a long-term assumption based on the best estimate of the long term expected investment earnings of the plan assets. The last component of plan expense is amortization of various plan experiences that are not anticipated by the plan’s actuarial
assumptions. For example, plan experience gains or losses and any plan design changes
would be amortized and included as a part of this component of plan expense. The
amortization can be either positive or negative.

In order to calculate the plan’s total pension benefit obligation and annual FAS 87
expense, the actuary uses a number of assumptions including a discount rate, mortality
table, salary increase rate, expected return on assets in the plan and expected future
contributions to avoid at risk status under the Pension Protection Act. The assumptions
used by the actuary are determined by the Company and reviewed by the Company’s
auditors.

Q. Do the calculations for the pension expense follow the described methodology of
FAS 87?
A. Yes. The amounts are calculated based on FAS 87 using information specific to the
Company’s Pension Plan.

Q. Please describe the development of the Pension Plan expense shown on line 1 of Exhibit
A-51 (HBK-1), which begins with $24,931,000 for 2008.
A. Each of the annual year end pension expense levels shown on line 1 for the gas utility is
based upon Hewitt’s actuarial determination of the plan’s expense for that year in
accordance with FAS 87 and also includes plan administration fees. The 12 months
ending September 2010 projected pension expense level is a combination of 25% of the
2009 Hewitt projected pension expense and 75% of the 2010 Hewitt projected pension
expense. The Consumers Energy pension expense determined by Hewitt’s actuary and
fees are allocated to the gas and electric portions of the utility using the accounting
department study methodology described earlier. This allocation method resulted in the
actual 2008 gas utility expense for pensions of $24,931,000. For 2009 and 2010, Hewitt has projected the Company’s FAS 87 expense based upon a series of specific assumptions for each year. The gas utility portions of the FAS 87 expense and administration fees for 2009 and the 12 months ending September 2010 are included on line 1. For 2009, the gas utility’s projected pension expense is $24,657,000. For the 12 months ending September 2010, the gas utility’s portion of the pension expense is $22,826,000.

Q. Why is the pension expense moderating beyond 2008?

A. The annual expense of the defined benefit Pension Plan is moderating for several reasons. First, the moderation reflects the fact that the Company stopped adding new participants to the defined benefit Pension Plan starting September 1, 2005. The defined benefit Pension Plan now contains a finite group of participants that, over time, will diminish until there are no longer any employees or retirees covered under this plan. Secondly, the expected pension expenses reflect the sale of the Palisades Plant, reorganization turnover, and the removal of associated liabilities under the Plan. Third, a larger portion of the pension cost is being capitalized since mid-2008 (26% vs. 24%). Fourth, the discount rate assumption was increased to 6.5% (from 6.4%) for 2009 and beyond, which impacts expense favorably. Finally, the pension plan assumptions (e.g. discount rate, salary increase, expected return on assets, asset values, etc) are being held constant over the projection period, which presumes no changes take place to the assumptions used to set the expense over the projection period.
Q. Does the Company intend to make any cash contributions to the Pension Plan during 2009 and during the 12 months ending September 2010? And if so, has this been factored into the Company’s presentation in this case?

A. The Company did not make any cash contributions to the Pension Plan during calendar year 2008. However, the Company plans to make a cash contribution on or before September 15, 2009 for the 2008 plan year, which will keep the Pension Plan funded at a level to avoid at-risk status as of January 1, 2009 as required under the Pension Protection Act. The final amount of this contribution has not yet been determined as it is dependent upon (1) the Pension Plan’s census update for 2009, (2) the Company’s funding interest rate decision under the Pension Protection Act and (3) any additional guidance or relief provided by the government. In addition, the Company will be making three additional quarterly contributions to the Pension Plan during 2009 for the 2009 plan year. On a total utility basis, the Company currently plans to make contributions to the Pension Plan of $291 million in 2009. In the 12 months ending September 2010, the Company expects to make cash contributions to the Pension Plan totaling $123 million for the utility. These cash contributions have been factored into the Company’s rate case presentation for expense purposes. Also, Company witness Mr. Alfred has made an adjustment for any working capital effects related to these cash contributions.

Q. Is the Company requesting that a Pension Equalization Mechanism (PEM) or pension tracker be reinstated with this rate case?

A. Yes. A Pension Equalization Mechanism is necessary to allow recovery of reasonable pension expenses, which are determined by various assumptions and market conditions over which the Company has no control. For instance, the significant downturn in...
security values in the 2008 financial markets reduced Pension Plan assets significantly by
the 12/31/2008 measurement date required under FAS 87 and used to project 2009’s FAS
87 Pension expense. This change in Plan asset values alone contributed to a $12 million
increase in total 2009 FAS 87 Pension expense, which, for 2009, was fortunately offset
by a similar reduction in this expense primarily due to the sale of the Palisades Plant and
resulting pension benefits liability and asset transfer to the new owner for these former
employees. However, continued poor investment performance in the financial markets
during 2009 and declining interest rates (over which the Company has no control) will
result in another significant increase in 2010 FAS 87 expense, which is not factored into
the pension expense projection for 2010 submitted with this case. On the other hand, if
the financial markets were to turn around and stabilize, it is possible there will be a
reduction in pension expense which would be of benefit to customers if a pension tracker
is in place. As pension expense is heavily influenced by various market factors over
which the Company has no control, a PEM or pension tracker is necessary to allow
recovery of reasonable pension expenses by the Company as well as to avoid recovery
from customers that is greater than the actual pension expense.

**Defined Company Contribution Plan**

Q. Does the Company provide an alternative plan for employees hired on and after
September 1, 2005?

A. Yes. In order to remain competitive in the area of a benefits package that attracts and
retains qualified and talented employees for the benefit of the customer, the Company
replaced the Final Average Pay and Cash Balance versions of the defined benefit Pension
Plan with the Defined Company Contribution Plan (DCCP) on September 1, 2005 for all new hires.

Q. Please provide a general description of the Defined Company Contribution Plan.

A. The Defined Company Contribution Plan provides an employer cash contribution of five percent of the employee’s base pay to that employee’s Savings Plan. No employee contribution is required to receive the Plan’s employer contribution. All employees hired on and after September 1, 2005 participate in this plan as part of their retirement benefit package.

Q. Are there any employees included in the Defined Company Contribution Plan that were hired before September 1, 2005?

A. Yes. Those employees who were hired between July 1, 2003 and August 31, 2005 and provided coverage under the Cash Balance version of the defined benefit Pension Plan became participants in the Defined Company Contribution Plan as of September 1, 2005. As of September 1, 2005 for this specific group of employees, additional pay credits under the Cash Balance version of the defined benefit Pension Plan were discontinued.

Q. Will the Cash Balance version of the defined benefit Pension Plan accept any new employees as participants?

A. No. As with the Final Average Pay defined benefit Pension Plan, the Cash Balance version of the defined benefit Pension Plan now has a finite group of participants that, over time, will diminish until there are no longer any employees or retirees covered under this Plan.
Q. Would you please explain Line 2 of your Exhibit A-51 (HBK-1) on the Defined Company Contribution Plan, which begins with $699,000?

A. Line 2 represents the expense related to the Defined Company Contribution Plan (DCCP). The actual gas operations expense for this Plan in 2008 was $699,000 as shown in column (b). The expected expense in 2009, shown in column (c), is $1,032,000 and is based upon the Company continuing to hire and turnover employees at a higher than usual rate due to larger numbers of expected retirements. Column (d) shows the expense of $1,264,000 which represents expense for the 12 months ending September 2010. All new hires will receive the 5% annual contribution to the Defined Company Contribution Plan after 90 days of employment instead of participating in the more costly defined benefit Pension Plan. The DCCP expense will continue to grow based upon an expectation that additional employees are hired each year and participate in the plan. On the other hand, the Company’s defined benefit Pension Plan expense is expected to decrease over time as the group covered by this plan is now finite in size and will reduce in number with the passage of time.

Q. As a result of the revised eligibility requirements for participation in the Final Average Pay defined benefit Pension Plan or the Cash Balance version of the defined benefit Pension Plan, is it correct to say that all new hire employees starting with September 1, 2005 and after will receive their retirement benefits through plans that are referred to as defined contribution type plans?

A. Yes. The two plans that will provide monetary benefits to this group of employees upon retirement are the Defined Company Contribution Plan and the 401(k) Savings Plan.
Q. Would you please explain line 3 of your Exhibit A-51 (HBK-1), which begins with $3,647,000?

A. Line 3 represents the Company’s gas operations expense related to the 401(k) Savings Plan. In 2008, the actual gas utility operating and maintenance cost for the Savings Plan was $3,647,000. In 2009, the expected gas utility operating and maintenance expense for the Savings Plan is $3,973,000. In the 12 months ending September 2010, the gas utility expense projected for the Savings Plan is $4,077,000.

Q. Please explain briefly how the Savings Plan works.

A. The Savings Plan is a 401(k) type retirement savings program funded by employee contributions and then a portion of those employee contributions are matched by Consumers Energy Company. The Company matches 60% of the first 6% of employee contributions. Employee contributions beyond 6% are not matched by the Company. Consumers’ expense includes the Company matching provision costs and the payments made to Fidelity for administration of the program. The Company match provision for the Savings Plan, which was suspended from September 2002 through 2004 due to corporate cost constraints, was reestablished beginning January 1, 2005.

Q. How is the Savings Plan expense that is common to gas and electric operations allocated to the gas portion of the business?

A. The Savings Plan expense is allocated in the same way as discussed previously for the Pension Plan and DCCP expenses using employee labor dollars.
Q. Please explain how the Savings Plan matching program is important to attract and retain employees.

A. The Savings Plan match for Consumers Energy employees serves two important purposes. First, the Savings Plan match helps provide a competitive benefits package that enables the Company to attract and retain qualified and talented employees, which directly and indirectly serve and benefit the customer. The Savings Plan match was made in CMS Energy common stock for many years to encourage company ownership and create an incentive for employees to perform well to the benefit of customers. On May 1, 2007, the Company match began to follow each employee’s chosen allocation for that employee’s own contributions to the Savings Plan and new investments in the CMS Stock Fund were no longer allowed. On November 1, 2007 the CMS Stock Fund was removed as an investment from the Savings Plan. These changes to the Company match and CMS Stock Fund investment assure broader diversification of employee retirement funds across a range of companies and market segments. These changes also reduce investment risk to employees, created from investing in a single security fund (CMS Energy Stock). These changes were particularly important to employees in the Savings Plan, as this Plan is a tool designed to build security for an employee’s retirement. In addition, these changes also reduce the Company’s exposure to potential employee shareholder lawsuits, which benefits customers.

Second, while most current employees are covered by the Company’s defined benefit Pension Plan, the Pension Plan by itself is not designed to meet employees’ complete retirement income needs. The Pension Plan is only part of an overall competitive employee retirement package that includes the Pension Plan, the
contributory Savings Plan and the Company matching contribution. These plans provide real incentive for employees to do well in their jobs to the benefit of customers because doing so over time will lead them to a more secure retirement, supported by their own personal savings and social security benefits.

Further, the Savings Plan match remains a competitive benefit practice in across the country as well as in Michigan. From time to time, Consumers Energy hires the actuarial firm of Hewitt Associates to compare its benefits to those of other companies. The most recent studies were done in June 2006. The companies in these comparison studies are other large Michigan employers or energy companies. Some of the companies in the most recent studies included DTE Energy, Kellogg, AT&T, Ford Motor Company, Dow Chemical, American Electric Power, Progress Energy, Public Service Enterprise, Steelcase and Duke Energy. Each study includes 11 to 15 comparable companies for competitive benefit analysis. These comparisons continue to show that almost all companies in the study provide a Savings Plan with a company match and that the match provided by other employers is generally higher than that provided by Consumers Energy under its match program. The majority of companies in these studies also provide a defined benefit pension plan or second defined contribution plan in addition to their savings plan match. The bottom line is that savings plans with a match are very much available from Michigan employers as well as from other energy company employers from which Consumers competes for employee talent. It is necessary to continue providing this highly visible, competitive benefit to employees of Consumers Energy in order to continue attracting and retaining competent employees needed by the Company, particularly in light of the large number of retirement eligible employees at the
Attracting competent, qualified employees and retaining this talent maximizes the efficiency of the Company’s labor force and reduces costly turnover. Retaining trained, experienced and competent employees works to the customer’s benefit.

The Savings Plan match also reflects a prudent business practice because it helps employees to create savings for their retirement. The match encourages employees to save more when their contributions are matched. Matching contributions offer an immediate, tangible return that employees contributing to the plan can see and appreciate. New employees are automatically enrolled in the Savings Plan due to the importance of starting to save early, as a secure retirement will depend significantly on how much the employee can contribute to the employee’s defined contribution account. Matching contributions and automatic enrollment in the Savings Plan are important features of the Plan that help create savings. These features are important because most retirement studies show that employees, including Consumers Energy employees, need to save more for their retirement than they currently do as many costs in retirement will continue to increase for them. Longer life expectancies are leading to longer retirements, which require more savings. Additionally, other costs are expected to continue to increase for retirees also, such as health care costs. The Company match encourages employees to plan and save for retirement. The Savings Plan provides an excellent vehicle to help employees achieve a more self-sufficient and independent retirement.
Q. Has the 401(k) Savings Plan match been included in rates previously ordered by the Michigan Public Service Commission (MPSC)?

A. Yes, expenses related to the 401(k) Savings Plan have been included in rates approved by the MPSC for Consumers Energy. The Commission included the Savings Plan match in the Final Order in Case U-13000 (dated November 7, 2002, page 49). Most recently, the MPSC included the Savings Plan match in its November 21, 2006 Final Order in Case No. U-14547 (page 52).

The Savings Plan match has been offered by Consumers Energy since 1961. The match was suspended from September 2002 through 2004 during a period of severe financial stress for the Company. At the time the suspension was announced, employees were assured the suspension was temporary and that the program would be reinstated. The match was reinstated on January 1, 2005. The assurance to employees that the match would be reinstated was very important in order to retain the Company’s skilled workforce and to be able to recruit new talent during the match suspension. The Savings Plan matching contribution has never been suspended prior to September 2002 because it is such a highly visible, competitive benefit practice used by Consumers Energy to attract and retain its skilled workforce.

Suspending the Company matching contribution to the Savings Plan was one of a number of self-help measures that were taken by Consumers Energy as a result of significant financial difficulties and cash flow problems. Employees sacrificed during a period of frozen rates in an effort to ensure that the Company could continue to serve customers. The cash flow savings from the self help measures enabled the Company to continue to serve customers.
Q. Is the Savings Plan match “discretionary”?
A. It is not discretionary for union employees. A provision in the Working Agreement ratified in 2005 with union employees assures these employees that the match will not be suspended during the five-year contract, which expires in 2010. This was an important issue during the labor negotiations, which was finally resolved through arms-length bargaining. With respect to non-union employees, there is not a similar contractual prohibition against suspension. However, the Savings Plan match is part of an overall competitive benefit package that employees expect to continue and the company plans to continue offering. The Company’s competitors continue to offer a savings plan match. As noted above, it is a benefit that helps the Company to attract and retain qualified and talented employees. As a practical matter, the Company views the match as non-discretionary.

**Active and Retiree Health Care, Life Insurance and Long-Term Disability**

Q. Which insurance benefits are you addressing?
A. I am addressing active employee health care, life insurance and long-term disability plans as well as retiree health care and life insurance. These expenses are shown on Lines 4 and 5 of Exhibit A-51 (HBK-1).

Q. Are the expenses for active employee health care, life insurance and long-term disability (LTD) benefits determined in the same way as expenses for retiree health care and life insurance benefits?
A. No. The expenses for active employees are based upon the actual costs for these benefits that have been incurred or are expected to be incurred. The expenses for retirees are
determined using actuarial analysis, which is performed by the Company’s actuary, in accordance with the Statement of Financial Accounting Standard (FAS) 106.

Q. How were the portions of active employee and retiree health care, life insurance and LTD costs allocated to gas operation and maintenance expense determined?

A. The portion of the Company’s total program costs attributable to the gas utility have been allocated to the gas and electric utility based upon an annual study by the accounting department of the relationship of the number of employees in the gas utility to the total number of employees in both the gas and electric utility. Then, the amount allocated to the gas utility is, in turn, allocated between operating and maintenance (O&M) expense and capital expense based upon the accounting department’s formula.

**Active Health Care, Life Insurance and Long-Term Disability (LTD)**

Q. Please describe the development of the active health care, life insurance, and long-term disability (LTD) insurance expenses levels that are shown on line 4 of Exhibit A-51 (HBK-1), which begins with $17,813,000 in 2008.

A. Line 4 contains expenses for the three Company-subsidized benefit plans for active employees’ health care, life insurance and LTD insurance. The primary component of this expense is health care, while life insurance and LTD expense make up a much smaller portion of the expense. In 2008, the Company incurred expenses of $17,813,000 for health care, life insurance and LTD for gas operations. This expense is projected to be $18,853,000 for 2009 and $19,940,000 for the 12 months ending September 2010.
Q. What factors did you consider in projecting the Company’s 2009 and 12 months ending September 2010 health care, life insurance and LTD expenses?

A. In projecting these expected health care cost increases, a number of factors were considered. Primary factors considered included the use of national trends survey information, the Company’s health carrier’s health cost trend expectation and claims experience for the Company, the age of the Company’s workforce and the implementation of the Company’s healthy living imitative for employees and retirees.

Q. Can you please explain how these factors were used to determine the Company’s health care cost increase?

A. To help determine the expected health care cost increases in the coming years, the Company continues to review health care consulting firms and other market survey information released periodically and related to expected health care cost increase trends in 2009 across the country. While most of the recent information indicates movement away from double-digit increases, national trend increases are still expected to be in the high single digits for 2009, depending upon the type of health plan offered. Recent health cost surveys by various consulting firms like Aon, Mercer, Watson Wyatt, Towers Perrin, Business and Legal Reports, and Milliman still indicate expected 2009 health care cost increases ranging from 6% to 12%. These trends are expected to continue for 2010.

The Company also reviews its own health care experience with a broad spectrum of experts managing the health plans offered to its employees and retirees. Continuing discussions and analysis occurs throughout each year with the Company’s health plans (Aetna, Blue Cross/Blue Shield of Michigan, Medco, Priority Health, Health Plus, Health Alliance Plan and Blue Care Network) about expected health care cost increases for
Consumers Energy over the next one to two years. These recent discussion and analysis with these health plans indicates a probable increase in health care costs for the Company that will fall into the 6% to 10% range annually.

While health care trends are moderating somewhat nationally, the Company’s health plans indicate that the Company’s workforce is older than the average in their plans, and, as a result, has a higher utilization rate of services that is associated with an older covered population. Of the Company’s current workforce, 58% of employees are over age 45; 41% are over age 50; and 19% are over age 55. The Company understands this aging trend affects its health care costs and has implemented a number of plan changes and programs discussed below to manage and control its health care costs. These changes include sharing health care cost increases with employees and retirees, plan design changes which require more cost sharing with participants, education on the prudent and informed use of health care benefits as well as the promotion of preventive services and the new healthy living initiative.

As a result of this analysis, health care costs are assumed to increase at an annual rate of 8% for the Company. However, health costs for 2009 are assumed to increase at only 6% over 2008 costs due to the introduction of Healthy Living benefit plans for most employees. These plans offer two coverage levels and it is assumed some employees will elect less generous coverage levels rather than participate in various healthy living activities required to maintain the higher coverage level. This will help to control the cost in 2009, but 2010 is expected to show an 8% increase over 2009 costs.

While national health cost increase averages are expected to be in the 6% to 12% range, the Company needs to consider the impact of its aging, highly skilled workforce
on its health care costs. However, the plan changes that have been made, and the fact
that employees and retirees are now participating in an ever expanding health
improvement, informed consumerism and a healthy lifestyle approach to health, will help
to control health cost increases for the Company and its employees over the next five to
ten years. In addition, the Healthy Living plans added in 2009 will definitely help
control Company health costs in 2009. As a result, the Company is expected to be able
to hold its annual health care cost increase for the 12 months ending September 2010 to
below 8%.

Q. What are some of the reasons that health care costs are increasing at a level higher than
general inflation?

A. There are a number of factors causing a much higher rate of health care inflation than are
reflected in the general CPI indexes. Health care costs are expected to continue rising
rapidly during the next several years due to an aging population living longer, additional
utilization of services, price increases for those services, new medical technology, cost
shifts from government plans, rising provider malpractice premiums, rapidly escalating
prescription drug price and use as well as the new medical services and drugs coming to
the market. These factors are outside the control of Consumers Energy. Even with all
the employee and retiree health plan design and premium contribution changes made by
Consumers over the past several years, health care costs for Consumers Energy are still
expected to continue increasing annually at a rate two to three times that of general
inflation. Assuming that health care costs will increase at the general rate of inflation has
not been the case for many years and is not expected in the foreseeable future.
Q. Are large increases in health care costs being experienced nationally?

A. Yes. National health care costs continue to increase at rates much greater than general inflation but are now below double digit increases as noted earlier.

Q. Are the significant increases in health care costs limited to active employees?

A. No. Health care costs are also increasing at a rate higher than inflation for retirees for the same reasons cited earlier. In fact, retiree expenses are generally increasing at higher rates due to the aging process and the resulting increases in utilization. The projected increases for active employee health care, like projected increases for retiree health care are substantial, reasonably expected to occur, and largely beyond the control of Consumers Energy.

Q. Are you aware of any instances in which the Commission has concluded that increases in health care costs should not be limited to inflation?

A. Yes. The Commission has recognized that active employee health care costs are rising at a much greater rate than that of general inflation in past cases. The Commission recognized cost increases larger than inflation for active health care in the November 7, 2002 Final Order in Case No. U-13000 (pages 48-49). The Commission recognized increases for health care costs at rates above inflation for Consumers Energy in its October 14, 2004 order in Case No. U-13730 (pages 24-27).

The Commission also recognized increases for health care costs above inflation for Consumers Energy in its December 22, 2005 order in Case No. U-14347, at pages 37-40. Most recently, in Case No. U-14547, the health care expenses adopted in this case reflected such expenses at a rate higher than inflation.
The Commission has also recognized that increases for health care costs are rising at levels above inflation in its April 28, 2005 order in Mich Con’s rate Case No. U-13898 and U-13899, on pages 69 and 70. In the Mich Con case, the Commission stated on page 70, “However, at the present juncture, health-care expenses do not appear to adhere to past patterns; rather, those expenses appear to be increasing at an unusual rate”. The Commission was persuaded that health costs were rising at a much greater rate than general inflation and granted additional rate relief to recognize this fact.

The Company has presented evidence supporting recognition of active employee health care cost increases expected to be below 8% in the 12 months ending September 2010. Using a lower general inflation rate for health care costs would significantly understate active employee health care costs.

Q. Please describe the development of the expense levels for active employee life insurance and long-term disability costs included in line 4.

A. A 4% annual average increase was used to develop the expenses for life insurance and long-term disability insurance for 2009 and the 12 months ended September 2010. In other words, 2009’s expense for these benefits to the Company will be 4% greater than the expense for these benefits in 2008 (not including the experience refund paid in 2008) and each succeeding year is 4% more than the preceding year’s expected expense. The 4% increase in these costs annually is reasonable to use as both life insurance and long-term disability premium costs are based on wage and salary levels. The 4% annual increase represents the normal, expected merit increase in salaries/wages incorporates salary adjustments made for job changes and promotions and also accounts for the
increases in coverage employees elect in life insurance and long-term disability coverage from year to year during the annual enrollment process.

Refunds due to good plan experience can lead to lower than expected costs as was the case in 2008. However, because refunds depend upon plan experience and are not guaranteed, the expense projections are based upon annual 4% increases in this cost.

Q. What has the Company done over the past several years to control the increase in active employee and retiree health care, life insurance and long-term disability expenses?

A. The Company has done a number of things to control active employee and retiree health care, life insurance and long-term disability costs since 2002. One extremely important cost control feature for retiree health care is that most health care plan changes made to the active employee health care plans to control costs are also made to the retiree health care plans to control their costs.

In 2002, the Company introduced a flexible benefits program, Benefits by Choice, to all salaried employees. This program included a redesign of all the insurance benefits plans including health care, life insurance and long-term disability plans. The primary focus of Benefits by Choice was to control health care costs. It introduced a four-tier flexible benefits health care program for salaried employees. The new health care plan required premium contributions based upon salary for the best coverage and offered two, lower coverage options as well as cash for opting out of coverage if covered by another plan. Employees opting to a lower coverage level had additional cost sharing through increased deductibles and coinsurance limits.

Under Benefits by Choice, life insurance coverage paid by the Company was increased, but the Company discontinued contributions to supplemental coverage for
employees to minimize any cost impact. In addition, the long-term disability benefit was changed to include a 50% option in addition to the 60% option. The lower 50% option did reduce participating employee and employer cost for this benefit.

In 2003, the Benefits by Choice plan was changed again and expanded to include all salaried pre-Medicare retirees, who are generally under age 65. The 2003 Benefits by Choice health care plan included a change to premium contributions based upon the cost of the plan elected instead of salary. In addition, the Company implemented a plan change that began to share health cost increases with salaried employees and retirees by way of passing on a percentage of the overall plan cost increase to employees via higher premium contributions. For 2003, the health care cost increase was shared equally between salaried employees and the Company. Pre-Medicare retirees, paying premium contributions for the first time in 2003, shared in slightly less than half of the cost increase for 2003. This sharing of the increase in costs resulted in premium contribution increases on the best coverage tiers (100%, 90% and 80%) offered under the program.

In addition to these changes, the mail order prescription drug copay was doubled in 2003 to further encourage use of generics, while retaining the economic incentives of using the mail order program. The mail order prescription copay in 2003 for a 90-day supply was increased to $15 for a generic prescription and $30 for a brand name prescription. Prior to 2003, the mail order copay was $7.50 for generic and $15 for a brand name prescription

The Company also changed the method used to coordinate benefits to a Maintenance of Benefits provision in all plans. Maintenance of Benefits limits reimbursement of dependent claims when other coverage pays first. Under the new
method of coordinating benefits, the Company’s plan limited the total reimbursement from its plan to what would have been paid had it been the only payer. The former coordination provision paid benefits on any remaining expenses following the first plan’s payment.

Salaried Medicare retiree’s (retirees over 65) supplemental health care coverage to Medicare was also changed in 2003. These retirees continued in the same Medicare supplemental plan, but were required to pay the same increased mail order prescription drug copays required of the salaried pre-Medicare retirees and employees. The maintenance of benefits coordination feature for coordinating benefits also was applied to all future salaried Medicare retirees.

In 2004, additional changes to control costs and improve quality of care were implemented for salaried employees and retirees. The major change involved introducing Preferred Provider Organization (PPO) plans to replace the gatekeeper Point of Service (POS) plans. This change allowed the Company to offer two large national PPO plans, benefiting from the competition this created to reduce administrative cost and producing additional claim savings as all salaried employees and pre-Medicare retirees were now covered by discounted networks nationwide.

In addition, Health Maintenance Organization (HMO) benefits were revised in 2004 to increase participant cost sharing in the benefits provided and to keep the HMO plans cost competitive with the new PPO plans being offered. Some of the HMO changes included introduction of three-tiered prescription benefit plans and increases in hospital, urgent care and emergency care copays.
The Company also changed its contribution method to a defined-dollar contribution method and shared one-half the anticipated cost increase in 2004 with salaried employees and pre-Medicare retirees. The Company changed its coverage contribution methodology to provide the same contribution amount (which included half of the anticipated cost increase) to each employee or retiree based upon family size (single, double or family) no matter which plan was chosen by the retiree. This forced the health plans offered to begin competing on total premium cost as employees and retirees paid all premium contribution cost over the defined-dollar contribution amount paid by the Company.

In addition, an informed consumerism approach was introduced for all employees and retirees covered by the Company’s health care plan in 2004. This included disclosure of health care cost information, credible health and wellness website information, plan benefit design changes such as PPO in-network deductibles to promote cost awareness, and PPO health/disease management program introductions. The goal of informed consumerism is to educate plan participants so they become more informed and prudent purchasers of health care goods and services, which will lead to improved quality and lower costs.

Finally, deductibles and out-of-pocket limits were increased in 2004 for the Company’s salaried Medicare retirees under the supplemental coverage plan provided to them by the Company.

In 2005, the Company again shared one-half of the premium cost increase with its salaried employees and pre-Medicare retirees to contain health costs. In addition, the Company implemented prescription drug coverage management programs for all salaried
employees and retirees to further contain cost increases in its prescription coverage and
improve the quality of its prescription drug plan.

Q. Were the health care plan changes noted above for 2002 through 2005 applied to active
OM&C union employees and retirees in addition to the salaried employee and retiree
groups?

A. Most of the Benefits by Choice program plan changes described above were not applied
to the active union employee and retirees. In general, these benefit changes were not
made for the OM&C union work group as health care benefits are provided for under the
OM&C union working agreement, which did not expire until June 1, 2005.

However, all OM&C employees and retirees with HMO coverage were subject to
the same cost sharing benefit design changes described above that were made in the
HMO plans for salaried employees and retirees from 2003 through 2005 as these benefits
are not covered under the collective bargaining agreement. In addition, in 2004 and
2005, the Company did include the OM&C union employees and retirees in the informed
consumerism communication and education program described above.

During 2005, the Company negotiated a new collective bargaining agreement
with its union employees, which contained a number of changes to control OM&C union
health care cost during the term of the new agreement for these employees.

Q. What changes were made in OM&C union employee health care for 2006 as a result of
the new union collective bargaining agreement?

A. For 2006, the newly ratified contract with OM&C union employees provides for a
significant number of health plan changes which will help control future Company health
care costs while making employees better consumers of health care services. The
Preferred Provider Organization (PPO) plans of Aetna and Blue Cross/Blue Shield are being offered, which allow all OM&C employees to be covered by discounted network agreements offered under at least one of these plans. Employees in either PPO are being reimbursed 85% (formerly 90%) of their covered expenses after a $225 single/$450 family in-network deductible (formerly $0 deductible) is satisfied. Coinsurance limits, medical copays and dental deductibles are all increased. Prescription drug coverage copays are increased over 30% at retail and doubled for mail order prescriptions. Prescription drug coverage management programs are added to promote more efficient prescription drug utilization and the use of the mail order program for maintenance prescriptions is required. A provision to handle specialty prescription drugs is also added to control this cost. Spouses of employees, who can obtain health care coverage from their own employers for under $110 in monthly premium, are only offered secondary coverage under the Company plan. Health management programs are included to help manage the cost and quality of care for various health conditions. Informed consumerism education and communication is promoting better use of health care services and further help to control these costs.

In 2006, all of the changes made for active OM&C union employees were also made for OM&C union pre-Medicare retirees. In addition, OM&C union Medicare retirees had their deductible, coinsurance limits and prescription drug copays increased to match those of the active employee OM&C union group. These Medicare retirees are also be covered by the prescription drug coverage management programs, required to use of the mail order program and have the specialty pharmacy benefit available to control health costs.
Salaried employees and pre-Medicare retirees shared in the health cost increase for its group for 2006 by contributing about 15% more in premium contributions for their health coverage. The prescription drug coverage management programs, required use of the mail order prescription program, specialty pharmacy benefit, increased dental deductible and $110 spouse coverage provision also now apply to all salaried employees and retirees in 2006.

Q. What changes to health care did the Company make for the 2007 plan year?

A. There were a number of changes made for 2007 as well. The health and insurance recordkeeping was moved to Fidelity Investments, a large employee benefits firm with significant technological capabilities. Consumers will be able to take advantage of Fidelity’s electronic efficiencies in eligibility administration and its offering of a health management center. The health management center will encourage health management among employees and retirees and will be used to promote managing one’s health and the use of informed consumerism, which should help curb health care increases over time.

In addition, severalPreferred Provider Organization (PPO) networks were expanded, offering larger discounts on claims. Health Maintenance Organizations (HMO) increased several copays for some services to help contain costs for the Company. Two HMO plans that were more costly were removed from the offering to employees and retirees. In the PPO plans for all employees and retirees, additional prescription drug coverage management programs to control costs and dispense appropriate prescription drugs were added to the prescription drug coverage benefit. These coverage management programs now include prior authorization, dose
optimization, generic substitutions, formulary first usage, quantity limits and safety program controls. All of these measures are an attempt to manage utilization by assuring that the most cost-effective drugs are being dispensed at the right time for the right purpose. On July 1, 2007, a safety and efficiency program was added to the PPO prescription drug benefit. This program implements claims data sharing on a regular basis between the medical and prescription drug plan carriers to help improve drug dispensing safety and control prescription drug and medical costs. For salaried employees and pre-Medicare retirees, premium contributions were increased an average 29% as they absorbed one-half of the expected total increase in health costs for 2007.

Finally, the Company announced that all new salaried hires on or after January 1, 2007, who meet retiree health care eligibility requirements at retirement, will be offered access-only retiree health care and the Company will not be contributing to the cost of their retiree health care coverage.

Q. What changes to health care did the Company make for the 2008 and 2009 plan years?

A. The most significant change for 2008 was the introduction of the Healthy Living initiative. Healthy Living is long-term health initiative designed to improve the health and productivity of the Company’s union and nonunion employee workforce as well as that of family members and retirees, most of who are covered by the Company’s health plan. This initiative seeks to promote and drive improvements in employee’s (including family members and retirees) overall health and wellness, engage them in health care decisions and healthy lifestyle choices and identify health problems early when they are more treatable and less costly. In 2008, Healthy Living includes promotion of and reward for completion of a Health Risk Assessment (HRA) and HRA follow-up health
improvement program as well as implementation of a long-term, company-wide health
promotion and education program.

In addition, a number of additional prescription drug coverage management
programs have been added for employees and retirees in 2008 plans. One Preferred
Provider Organization plan was eliminated for union employees and Pre-Medicare
retirees due to its higher cost. Four HMO plans were eliminated due to high cost or
consolidation into four large remaining HMO plans, which now provide statewide
coverage at more affordable rates. Finally, salaried employees and Pre-Medicare retirees
have higher premium contributions for 2008 as they picked up 50% of the expected cost
increase in their health care benefits.

In 2009, the Company restructured most of its health care plans to provide
incentives for healthy living and control costs. Healthy Living plans were introduced to
employees and pre-Medicare retirees. These plans provide a preferred coverage level of
benefits (similar to 2008 levels) for employees/pre-Medicare retirees and covered
spouses who complete a Health Risk Assessment and set a health improvement plan.
Employees/pre-Medicare retirees and/or covered spouses, who elect not to complete
these two healthy living requests, are placed in a less generous, standard benefit coverage
level with higher deductibles, copays and coinsurance limits on April 1. In addition,
health plan offerings were consolidated as the 90% and 80% PPO offerings were
combined into a new 85% PPO plan to reduce administrative costs. Additional
prescription drug coverage management programs were implemented for all employees
and retirees to properly control utilization and costs of more expensive prescription
drugs. Adult immunizations, dental coverage, emergency room copays and eye exam
benefits were changed to promote healthy living lifestyles and better control future costs. Finally, half of the expected 2009 health cost increase was passed onto salaried employees and pre-Medicare retirees with higher premium contributions. As a result of all these changes, the Healthy Living plans are expected to hold the Company’s health cost increase to 6% in 2009.

The Company expects to continue promoting the Healthy Living initiative through the health care benefits provided in order to engage a large percentage of its workforce in healthier lifestyles. This initiative is expected to result in productivity and attendance improvements as well as better control of health care costs in the future.

Q. Are the health care, life insurance and long-term disability benefits competitive in the market?

A. The health care, life insurance and long-term insurance benefits are competitive in the market. The Company uses Hewitt Associates benefit comparisons periodically to assess competitiveness of its insurance benefit programs. In June 2006 the Company assessed the competitiveness of its benefit programs relative to a number of energy-based and Michigan-based companies. These benefit comparisons provided by Hewitt associates indicate that the current benefit plans for employees are competitive and similar to the plans offered by competitor companies. These are the same competitive benefit studies referenced earlier for retirement benefits comparisons.

A competitive health care plan that is cost-effective and quality based is very important to attracting quality employees, keeping them healthy and productive, and on the job serving customers.


**Retiree Health Care and Life Insurance**

Q. Would you please explain line 5 of your Exhibit A-51 (HBK-1), Summary of Benefits O&M Expense or the Years 2008-2009 and 12 Months Ended September 2010 – Gas Portion, which begins with $18,327,000 in 2008?

A. Exhibit A-51 (HBK-1) shows the actual 2008 retiree health care and life insurance expense (also known as OPEB or FAS 106 expense) as well as the projected retiree health care and life insurance expense for 2009 and the 12 months ending September 2010. These expenses are shown before any adjustments are made due to the OPEB (Other Post Employment Benefits) Equalization Mechanism (or OPEB tracker). Line 1 represents the operating and maintenance (O&M) expense associated with the Company’s retiree health care and life insurance plans attributable to the gas portion of the utility operations.

Each of the annual expense levels shown on line 5 is the total of three separate items which make up the total expense. Each year’s expense contains (1) a FAS 106 expense calculation, (2) an amortized FAS 106 transition obligation expense, and (3) an actuarial services expense.

Q. How does the Company determine its FAS 106 expense for retiree health care and life insurance?

A. The expense is determined using actuarial analysis that is performed in accordance with Statement of Financial Accounting Standards (FAS) 106. Consumers Energy follows Generally Accepted Accounting Principles (GAAP) for its financial statements. Under the provisions of GAAP, FAS 106 describes the methodologies and assumptions required to properly calculate and account for retiree health care and life insurance expense. The
calculations required by the accounting standards are performed annually by Consumers
Energy’s actuary, Hewitt Associates. In addition, the actuarial assumptions are reviewed
by the Company’s auditors to insure consistency with GAAP.

FAS 106 requires an annual determination of retiree health care and life insurance
expense, also known as Other Post Employment Benefits (OPEB) or FAS 106 expense.
Expense is determined based on actuarially reviewed employee census data, the plan
provisions, plan assets and certain other actuarial assumptions. Year-end disclosure
information is also produced, based on these accounting standards, to show a
reconciliation of plan assets and liabilities at the end of the Company’s fiscal year.

Q. What are the components of the annual FAS 106 retiree health care and life insurance
expense?

A. There are four components of this annual FAS 106 expense: (1) service cost, (2) interest
cost, (3) expected earnings on plan assets, and (4) amortization of gains and losses, prior
service costs, and any transitional amounts. Service cost represents one-year’s pro-rata
share of the expected benefits earned during the year by current active employees.
Interest cost represents interest on the plan’s benefit obligation (its liabilities) due to the
passage of time. All future benefits are discounted back to the valuation date based upon
an interest (discount) rate assumption. The discount rate used reflects the economic
conditions at the time the expense is being determined. There is also an assumption
made on expected return rates on assets for the year, which gets measured against the
actual returns for the period. This rate of return assumption is intended to be a long-term
assumption based upon the best estimate of long-term expected investment earnings of
the plan assets. The last component represents amortization of various plan experiences
that were not anticipated by actuarial assumptions.

In order to calculate the plan’s total benefit obligation and annual FAS 106
expense, the actuary uses a number of assumptions including health care inflation trend
rates, mortality table, retirement rates from the Company, actual retiree health care and
life claims experience specific to the Company, a discount rate and expected plan
contributions. Assumptions used by the actuary are reviewed by the Company’s auditors.

Q. What is the amortized FAS 106 transition obligation expense?
A. The amortized transition obligation expense component is a portion of the retiree health
care and life insurance expense that was determined at the time FAS 106 was first
implemented and remains unchanged from year to year.

This transition obligation expense was first established when FAS 106 became
effective in 1992 and the Company had to determine its retiree health care/life insurance
benefit obligation (liability) under the new accounting standard. Consumers Energy
adopted FAS 106 effective January 1, 1992. Under FAS 106, the transition obligation
produced a retiree health care and life insurance expense (representing benefits already
earned as of the date the FAS 106 standard became effective) and amortized that expense
on a straight-line basis over the average remaining service period of active plan
participants. The MPSC has previously approved recovery of this expense component,
which generally does not change form year to year during the amortization period.

Q. Are actuarial services expenses included in line 5 of Exhibit A-51 (HBK-1)?
A. Yes, an annual expense for the actuarial services provided for the retiree health care and
life insurance plans is included in line 5 of the exhibit.
Q. Do the calculations for the retiree health care and life insurance expense follow the described methodology of FAS 106?

A. Yes. The amounts are calculated based on FAS 106 using information specific to the Company’s retiree health care and life insurance plans.

Q. Please describe the development of the retiree health care and life insurance expense levels that are shown on line 5 of Exhibit A-51 (HBK-1), which begins with $18,327,000 in 2008.

A. Each of the retiree health care and life insurance expense levels shown on line 5 for the gas utility is based upon Hewitt’s actuarial determination of the plan’s expense for that period in accordance with FAS 106 and includes the amortized FAS 106 transition obligation as well as the cost for actuarial services related to these plans. The actual 2008 retiree health care and life insurance expense for the gas utility was $18,327,000. The operating and maintenance expense for retiree health care and life insurance is projected to be $30,815,000 in 2009 and $30,232,000 for the 12 months ended September 2010 for the gas utility.

To determine the annual FAS 106 expense for Consumers Energy for the 12 months ending September 2010, key actuarial assumptions are used in the expense projection by the actuary at Hewitt. These assumptions include a 6.50% discount rate, 7.75% return on assets, 8.5% pre-Medicare retiree and 8.0% Medicare retiree health care cost trends, annual trust contributions of $53 million, use of the 2000 mortality table, as well as Consumers Energy’s acceptance of the government subsidy available under the Medicare prescription drug legislation. Using these assumptions, the actuary calculated the FAS 106 expense to be $78,000,000 in 2009 and $75,000,000 in 2010 for Consumers...
Energy. For the 12 months ending September 2010, the FAS 106 expense is projected to be $75,750,000 (using 25% of the 2009 and 75% of 2010 projected FAS 106 expense from Hewitt). Using the headcount allocation methodology mentioned previously, the gas O&M portion of this total FAS 106 expense for the 12 months ending September 2010 is $19,619,000.

The annual transition obligation expense for Consumers Energy totals $23,179,000. The allocation methodology to determine capital and operating expense components for the transition obligation is different from the annual FAS 106 component described above. Because the transition obligation was set when the FAS 106 standard became effective, it measured the total benefit obligation already established at that time. As a result, this portion of the transition obligation was considered historical and could not be capitalized. Another much smaller portion of the transition obligation, the deferred service and interest cost, accounts for cost incurred after FAS 106 adoption and prior to the MPSC rate cases on FAS 106 recovery. As a result, the majority of the transition obligation expense is operating expense and it is amortized over a set number of years as previously authorized by the MPSC. In addition, the allocation of the total transition obligation expense between the gas and electric utility was also set by the accounting department based upon the headcount relationship of gas and electric at the time the transition obligation was first established and does not change from year to year. Under this annual transition obligation expense allocation methodology established by the accounting department, the gas operations O&M portion of the this transition obligation expense for the 12 months ending September 2010 is $10,567,000.
The remaining piece of the gas operating and maintenance cost for retiree health care and life insurance for the 12 months ending September 2010 is $46,000 for actuarial services related to maintenance of the plan and preparation of required actuarial reports.

The three separate items of retiree health care and life insurance O&M expense outlined above show the total gas utility expense of $30,232,000 for the 12 months ending September 2010.

Q. Why are retiree health care and life insurance costs increasing so much in 2009 and for the 12 months ending in September 2010?

A. There are two primary major reasons for these increases. First, the retiree health care trend rate assumption for future years for both pre-Medicare and Medicare retirees has been changed to better reflect expected future health costs for these retirees during both of these time periods. As part of this change, the ultimate year trend rate, where health cost increases are expected to run at 5% annually, has also been pushed forward to 2017 from 2011 (for pre-65 retirees) and 2013 (for post-65 retirees). Second, the poor investment performance of the OPEB plan assets in 2008 is now reflected in the expected 2009 and 12 months ending September 2010 expenses for retiree health care and life insurance.

Q. Is the Company requesting that an OPEB (Other Post Employment Benefits) Equalization Mechanism (OEM) or OPEB tracker be reinstated for retiree health care and life insurance expenses with this rate case?

A. Yes. An OPEB Equalization Mechanism is necessary to allow recovery of reasonable retiree health care and life insurance expenses, which are determined by various assumptions and market conditions over which the Company has no control. For
instance, the significant downturn in security values in the 2008 financial markets reduced OPEB Plan assets significantly by the 12/31/2008 measurement date required under FAS 106 and used to project 2009’s FAS 106 OPEB expense. This change in Plan asset values alone contributed to a $39 million increase in total 2009 FAS 106 OPEB expense. In addition, the assumption change required to properly reflect retiree health care inflation trends created an additional $14 million in FAS 106 OPEB expense in 2009. Continued poor investment performance in the financial markets, declining interest rates and continued health care market inflation during 2009 (over which the Company has no control) will add another significant increase in 2010 FAS 106 expense, which is not factored into the FAS 106 retiree health care and life insurance expense projection for 2010 submitted with this case. On the other hand, if the financial markets were to turn around and stabilize, it is possible there will be a reduction in retiree health care and life insurance expense, which would benefit customers if an OPEB tracker is in place. As FAS 106 retiree health care and life insurance expense is heavily influenced by various market factors over which the Company has no control, an OEM or OPEB tracker is necessary to allow recovery of reasonable retiree health care and life insurance expenses by the Company as well as to avoid recovery from customers that is greater than the actual retiree health care and life insurance expense.

Q Does that conclude your direct testimony?

A. Yes.
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
distribution of natural gas and for other relief

Case No. U-15986

DIRECT TESTIMONY

OF

RACHEL L. PENDER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business address.
A. My name is Rachel L. Pender. My business address is One Energy Plaza, Jackson, Michigan.

Q. By whom are you employed and what is your present position?
A. I am employed by Consumers Energy Company (“Consumers Energy” or “Company”) as a General Rate Analyst II within the Rates and Business Support Department. I joined the Rates and Business Support Department in March of 2002 as a Rate Analyst and continued working for the Company until taking a leave of absence in February of 2006 in support of my husband’s military service. In June of 2008, I returned to Consumers Energy in my current position.

Q. Please state your educational background.
A. I graduated from Lake Superior State University in May of 2001 with a Bachelor of Science degree in Business Administration. In addition, I have attended a number of courses on utility ratemaking.

Q. What are your responsibilities as a General Rate Analyst II?
A. As a General Rate Analyst II, the main focus of my position centers on tariff issues, including interpretations, development and compliance. I also perform regulatory research, implement rate orders, review legislation and analyze the practices and rates of other utilities, which could potentially impact the Company’s Gas and Electric business.

Q. Have you previously testified in any regulatory proceedings before the MPSC?
A. Yes, I was a witness in Consumers Energy’s electric rate case, Case No. U-14347, sponsoring the Company’s proposed tariff changes and rate schedules.
Q. What is the purpose of your testimony in this proceeding?
A. I am sponsoring the Company’s rate design in this case including proposals for a self-implemented interim rate increase, a revenue decoupling mechanism (RDM), an uncollectible true-up mechanism (UTM), a Pension Equalization Mechanism (PEM), and an Other Post Employment Benefits Equalization Mechanism (OEM) as well as all tariff and rule changes.

Q. Please identify the exhibits you are sponsoring.
A. I am sponsoring the following exhibits:

- **Exhibit A-52 (RLP-1)** Calculation of Test Year September 2010 Potential Interim Surcharges
- **Exhibit A-53 (RLP-2)** Revenue Decoupling Mechanism – Gas Illustrative Example
- **Exhibit A-54 (RLP-3)** Schedule F-2, Summary of Test Year September 2010 Proposed Gas Rate Increase
- **Exhibit A-55 (RLP-4)** Schedule F-3, Calculation of Test Year September 2010 Current and Proposed Revenues by Rate Schedule
- **Exhibit A-56 (RLP-5)** Schedule F-4, Comparison of Typical Bills under Current and Proposed Rates
- **Exhibit A-57 (RLP-6)** Summary of Tariff Changes
- **Exhibit A-58 (RLP-7)** Schedule F-5, Proposed Tariff Sheets, M.P.S.C. No. 2 - Gas (Redlined Version)

Q. Were these exhibits prepared by you or under your supervision?
A. Yes.
RATE DESIGN AND TARIFF CHANGES

Q. Please describe Consumers Energy’s rate design objectives in this case.
A. The Company seeks to design rates that equitably collect costs from customers, reflect the cost of providing service, encourage efficiency, and provide the Company with a fair opportunity to recover the approved revenue requirement.

Q. Is Consumers Energy proposing any changes to its current rate design?
A. The Company is proposing to retain the traditional three-part price structure for sales customers consisting of a fixed monthly customer charge, volumetric distribution charges and gas commodity charges. Similarly, the Company is proposing to retain the current two-part price structure for transportation customers consisting of a customer charge and volumetric distribution charges. While the Company is not proposing any changes to the current structure of its gas rates, the Company is proposing a revenue decoupling mechanism (RDM) and an uncollectible true-up mechanism (UTM). In addition, the Company anticipates that it will implement an interim surcharge effective 180 days after the date of this filing, in accordance with the provisions of 2008 PA 286. I am providing an illustration of how that surcharge would be determined.

Self-Implemented Interim Rate Increase

Q. Why has the Company prepared Exhibit A-52 (RLP-1) Calculation of Test Year September 2010 Potential Interim Surcharges?
A. The Company has prepared Exhibit A-52 (RLP-1) in response to 2008 PA 286 that permits utilities to self-implement up to the amount of the requested rate increase if the application is found to be complete and if the Commission has not issued an order to the contrary within 180 days of the filing of a complete application. Exhibit A-52 (RLP-1) is an
illustration of the interim surcharge based on an equal percent increase as applied to all rates. This illustration assumes the Company will collect 100% of the revenue deficiency in this case on an interim basis. However, the Company may elect to implement something less than 100%. Exhibit A-58 (RLP-7), Proposed Tariff Sheets, M.P.S.C. No. 2 - Gas (Redlined Version), contains Sheet D-1.10, a redlined surcharge sheet that would be filed with the Commission prior to implementation of an interim surcharge.

Revenue Decoupling Mechanism

Q. Please describe what is meant by the term “revenue decoupling”.

A. Revenue decoupling is the severing of the utility’s revenue recovery from volumetric sales levels. This may be accomplished in several ways. The two most common methods include the collection of all fixed costs through a flat fixed monthly charge, known as Straight Fixed Variable decoupling; the second most common method is accomplished through revenue adjustment mechanisms that true-up the actual revenue collected with the level of revenue authorized on a prospective basis, commonly referred to as account-balancing.

Q. Why is Consumers Energy proposing a revenue decoupling mechanism?

A. The introduction of energy optimization programs as required by 2008 PA 295 will require that Consumers Energy make a significant investment in improving its customer’s energy efficiency, which will reduce the Company’s sales volume. The Company has filed its Energy Optimization (EO) Plan in Case No. U-15805/15889 and according to that Plan, annual gas deliveries will be reduced by 1,043,566 Mcf through 2010¹. Because the Company collects most of its fixed costs through volumetric charges, any

reduction in sales below the level used to establish rates increases the Company’s risk that it will be unable to collect the amount of revenue that was authorized in its rate case. A revenue decoupling mechanism can align the interests of customers and the utility, because it will ensure that the utility is able to collect its authorized revenue, which in turn removes the disincentive of the utility to promote energy efficiency.

Q. If customers’ natural gas usage decreases, wouldn’t Consumers Energy’s costs decrease as well?

A. The gas commodity costs would be reduced, but not the Company’s fixed distribution costs. Consumers Energy’s gas distribution system, like those of other gas utilities, is characterized by high fixed costs that do not significantly vary with changes in customer usage. When sales fall below the level used to establish the utility’s rates in its last rate case, the utility is unable to collect its authorized level of revenue and thus is denied a reasonable opportunity to earn its authorized rate of return. The MPSC Staff’s Report on Energy Efficiency, submitted to the Commission on January 31, 2006 in Case No. U-14667, acknowledges this impact.

Q. Has there been industry movement towards implementation of decoupling mechanisms?

A. Yes, according to the American Gas Association ("AGA"), there are currently 26 gas utilities in 13 states that have implemented decoupling tariffs, and gas decoupling programs are pending in a number of other states.\(^2\) Many of these utilities utilize a sales adjustment mechanism that allows for the reconciliation of annual sales and approved rate sales levels. Rates are then adjusted prospectively based on the utilities’ over- or under-collection of approved revenues. Some of the decoupling mechanisms adjust for

---

\(^2\) Natural Gas Rate Round-up, American Gas Association, July 2008.
non-weather related changes in usage and others include variations in usage caused by weather. I should also note that, in the December 23, 2008 Order in Case No. U-15506, the Commission directed Consumers Energy to include a revenue decoupling mechanism in its next general gas rate case filing.

Q. Does 2008 PA 295 address revenue decoupling?

A. Yes, I am advised that 2008 PA 295 provides in Sec. 89 (6) that natural gas utilities spending a minimum of 0.5% of total natural gas sales revenues, including commodity costs, annually on Commission approved energy optimization programs are authorized to implement a symmetrical revenue decoupling true-up mechanism that adjusts for sales volumes that are above or below the projected levels that were used to determine the revenue requirement authorized in the most recent rate case.

Q. How would the RDM proposed by the Company be structured?

A. Consumers Energy is proposing that the RDM be applicable to all retail and transportation gas customers. The RDM would establish a baseline average annual usage per customer for each customer rate class (“baseline average Mcf”) as approved by the Commission in the most recent general rate case. Annually thereafter, the Company would determine the actual annual average consumption per customer class (“actual average Mcf”) and compare that to the baseline average for each rate class. If the actual average Mcf is below the baseline average Mcf, then Consumers Energy would multiply the difference by the number of customers in that class as established in the most recent general rate case. The resulting volume would then be multiplied by the distribution charge as approved by the Commission in the most recent general rate case, to derive the total amount of revenue to be collected from that rate class. Consumers Energy proposes
to collect this amount through an equal per Mcf surcharge applied to all customers in that class over the subsequent 12 months following Commission approval. At the end of the 12-month period, Consumers Energy would determine any over- or under-collection of the RDM amount and roll that amount into the determination of the next period RDM adjustment.

If the actual average Mcf is higher than the baseline average Mcf for a rate class, then Consumers Energy would use the same methodology to determine the over-collection of revenue and calculate a per Mcf credit to be returned to customers in that class over a subsequent 12-month period.

Consumers Energy proposes to reconcile the RDM along with its annual EO reconciliation process to permit timely collection or refund of significant amounts.

Q. Please describe how the RDM would be applied.
A. I have provided an example of how the revenue decoupling mechanism would be applied in Exhibit A-53 (RLP-2) Revenue Decoupling Mechanism – Gas Illustrative Example.

Q. What customer classes does the Company propose to use in the application of the RDM?
A. For the gas utility, the Company proposes to apply the RDM to residential, general sales and transportation customer classes.

Q. Would RDM apply to customer choice sales?
A. Yes, the RDM would apply to customer choice sales. They would be included in their respective rate class.

Q. What accounting approvals are necessary to implement the RDM?
A. Deferred accounting must be followed to periodically record the results of the RDM. As discussed by Company witness Daniel Harry, the use of deferred debits or credits is
appropriate until the under-recovery is fully collected or the over-recovery is fully refunded. The Company requests Commission approval of this accounting treatment.

Q. Why is Consumers Energy proposing the decoupling mechanism explained above as opposed to other potential decoupling methodologies?

A. The Company believes this approach will enable Consumers Energy to maintain its traditional rate design which maximizes the incentive to participate in the EO program and continues to motivate customers to improve energy efficiency. This methodology is also administratively simple to implement and eliminates the contentious issue of establishing sales in future general rate cases.

Q. Would Consumers Energy oppose other decoupling methodologies?

A. Consumers Energy would not oppose other decoupling methodologies if they adequately addressed the sales volatility issue in a timely manner and provide the Company with a reasonable opportunity to collect authorized revenues.

Uncollectible True-up Mechanism (UTM)

Q. Please explain the Company’s proposal regarding the treatment of uncollectible expense.

A. As described in the testimony of Company witness Harry, Consumers Energy’s projected uncollectible write-off expense is anticipated to be $34.87 million for the 12-month period ended September 2010. This increase reflects the rapid decline in Michigan’s economy, which directly impacts Michigan’s unemployment rate. To protect Consumers Energy and its customers from the potential future volatility in uncollectible expense, the Company is proposing that the Commission approve an Uncollectible True-up Mechanism (UTM).
Q. Please explain how the UTM will work.

A. The Company proposes to create a +/-5% deadband such that if actual uncollectible expense in future years is within 5% of the base uncollectible expense amount as established in this rate case, no adjustment would be made. However, if the annual uncollectible expense is 105% or greater of the base uncollectible expense level approved by the Commission in this case, then the Company would, following notice and hearing, prospectively adjust rates upward, through an appropriate surcharge, so the Company is collecting 100% of the amount over the 5% deadband. If, on the other hand, the annual uncollectible expense is 95% or less of the base uncollectible expense level, then the Company would refund the amount outside the 5% deadband.

Q. Why is only 95% of the difference subject to collection or refund?

A. Although the actual level of uncollectible expense is completely out of the Company’s control, I propose that the Company remain at risk for five percent of its uncollectible expense as an incentive to minimize the expense to the greatest extent possible.

Q. How will the UTM be reconciled?

A. The Company will submit an application including the information on any difference between the uncollectible allowance and the actual uncollectible amount by March 31 of each year for the preceding calendar year. The application would be noticed with an opportunity for a hearing. The elements of the application should be narrow enough in scope to allow a prompt hearing and Commission order to facilitate timely implementation of the UTM credit or surcharge.
Q. Why is Consumers Energy proposing a Pension Equalization Mechanism?
A. The sensitivity of pension expense to changes in both interest rates and asset returns creates a significant potential for large variability in future pension expenses. Since pension expense is recognized in rates, both customers and the Company would benefit from a mechanism that eliminates the risk of future volatility in pension expense. As discussed by Company witnesses Kops and Harry, the Pension Equalization Mechanism (PEM) would allow the Company to annually defer the difference between the pension expense included in rates with the actual annual pension expense recorded by the Company.

Q. Please explain how the PEM will work.
A. The PEM reconciliation will be included in the annual Reconciliation of Gas Cost Recovery Costs and Revenues. Combining the PEM with the annual GCR reconciliation eliminates the need for a separate proceeding. If annual pension expense is greater than the expense in rates, this difference would be recognized as a regulatory asset for future recovery and collected though a monthly equal amount per Mcf surcharge to customers. If annual pension expense is less than the expense in rates, this difference would be recognized as a regulatory liability and will be distributed to customers through a monthly equal amount per Mcf credit.

Q. Is there any precedent for this mechanism?
A. Yes. The Company was authorized to implement a PEM in its November 21, 2006 order in Case No. U-14547. The PEM was terminated as a result of the August 21, 2007 order approving the partial settlement agreement in Case No. U-15190.
Other Post Employment Benefits Equalization Mechanism (OEM)

Q. Why is Consumers Energy proposing an Other Post Employment Benefits Equalization Mechanism (OEM)?

A. The sensitivity of Other Post Employment Benefits (OPEB) expense to changes in both interest rates and asset returns creates a significant potential for large variability in future OPEB expense. Since OPEB expense is recognized in rates, both customers and the Company would benefit from a mechanism that eliminates the risk of future volatility in OPEB expense. As discussed by Company witnesses Kops and Harry, the Other Post Employment Benefits Equalization Mechanism (OEM) would allow the Company to annually defer the difference between the OPEB expenses included in rates with the actual annual OPEB expense recorded by the Company.

Q. Please explain how the OEM will work.

A. This mechanism will work in the same way as the PEM described above.

Q. Is there any precedent for this mechanism?

A. Yes. The Company was authorized to implement an OEM in its November 21, 2006 order in Case No. U-14547. The OEM was terminated as a result of the August 21, 2007 order approving the partial settlement agreement in Case U-15190.

Rate Design

Q. Please describe Consumers Energy’s approach to rate design in this case.

A. Consumers Energy has designed delivery rates based on an equal percentage increase of 16.7% for all sales rates, including Residential Rates A and A-1, and General Service Rates GS-1, GS-2 and GS-3. The Company is proposing a separate and slightly higher equal percent increase to the delivery rates for the Transportation class, however the
larger percent increase does not fully reflect the Transportation class’ cost to serve as identified in the 2010 Cost of Service Study sponsored by Company witness Thomas Yehl and shown in Exhibit A-74 (TAY-2). The proposed revenue requirement for the transportation class was adjusted to mitigate rate shock for this class, while still moving them closer to their cost to serve. The Company is proposing that all Transport delivery rates be increased by an equal percent of 20.6%.

Delivery rates were designed to recover the target revenue requirement of approximately $84.8 million for Residential Service rate schedules A and A-1. For General Service rate class (which includes GS-1, GS-2 and GS-3), the Company used the total delivery cost of service of approximately $22.3 million for that class as the target revenue requirement. The proposed target revenue requirement for the Transport class is $6.8 million.

Residential Class Proposed Rates

Q. Please describe how the Company proposes to set prices to recover the residential revenue requirement?

A. Consumers Energy proposes to increase the Customer Charge for residential customers billed under Rate Schedules A and A-1 from $9.50 per month to $11.00 per month, based on the customer charge study in Exhibit A-74 (TAY-2) page 6 of 6. Consumers Energy proposes to increase the volumetric Distribution Charge from $2.0819 per Mcf to $2.6188 per Mcf to recover the remaining revenue requirement for the residential rate class. Proposed rates for Rate A customers are shown on Exhibit A-54 (RLP-3).
Q. Is the Company recommending a price change to the Excess Peak Demand Charge for residential Rate A customers?

A. Yes. Since the Excess Peak Demand Charge is customer related, Consumers Energy proposes to increase this charge by the same percent increase of 15.79% as the Residential Customer Charge, which represents an increase from $0.0489 per Mcf to $0.0566 per Mcf. The proposed Excess Peak Demand charge is shown on Exhibit A-54 (RLP-3), line 12.

Residential Income Assistance Service Provision

Q. Why is the Company proposing an Income Assistance Service Provision?

A. The Company is proposing an Income Assistance Service Provision as a means to alleviate the impact of escalating utility costs for customers who are income challenged. A similar provision was approved by the Commission in the Company’s last electric rate case (Case No. U-15245) and this proposal is consistent with the approved Income Assistance Service Provision approved in that case.

Q. Please describe the customer qualifications for the Income Assistance Service Provision.

A. To qualify for the Income Assistance Service Provision, total annual household income of the residence shall not exceed 150% of the Federal Poverty Level. Consumers Energy will enroll eligible gas customers upon notification from a qualifying assistance or governmental agency. Combination gas and electric customers that currently receive the Company’s electric residential Income Assistance Service Provision qualify for the gas residential Income Assistance Service Provision automatically.
Q. How is the provision structured?

A. Qualifying low-income customers being served on Residential Service Rate A will receive a fixed credit equal to the proposed customer charge, a credit of $11.00 per month. Thus, the customers on this provision will pay only for the volume of gas they use and will not be subject to a fixed monthly charge.

Q. Why is this provision necessary?

A. The Company recognizes the impact of current economic conditions and understands that the need for assistance is on the rise. In such bleak economic times, the Company understands that more customers are living on a fixed income and finding it difficult to pay for basic necessities. Consumers Energy believes that this is the right time for the introduction of an Income Assistance Service Provision for the Company’s Residential Service Rate A gas customers.

Q. Is the Income Assistance Service Provision available to customers taking service under the Company’s Rate Schedule A-1?

A. No. Rate Schedule A-1 customers consist of two or more residences and are served through a central meter. A common example is an apartment building in which natural gas service is centrally metered and the landlord, or the managing entity, is billed a single customer charge. The intent of this provision is not to offer discounts to landlords, but to provide Consumers Energy’s residential customers who need assistance with a credit. The rate is not intended to lower costs for property owners or developers who may not pass the savings on to the actual tenants occupying the buildings.
Q. Please describe how the Company proposes to set prices to recover the General Service Rate GS-1 revenue requirement.

A. Consumers Energy proposes to increase the GS-1 Customer Charge from $10.50 per month to $12.25 per month and increase the Distribution Charge from $1.9259 per Mcf to $2.2464 per Mcf.

Q. Please describe how the Company proposes to set prices to recover the General Service Rate GS-2 revenue requirement.

A. Consumers Energy proposes to increase the Customer Charge from $16.00 per month to $19.00 per month and increase the Distribution Charge from $1.7477 per Mcf to $2.0353 per Mcf. These charges maintain the economic break even points between Rate GS-1 and Rate GS-2 (384 Mcf annually), between Rate GS-2 and Rate GS-3 (6,702 Mcf annually) and provide for recovery of the Rate GS-2 revenue requirement.

Q. Please describe how the Company proposes to set prices to recover the Rate GS-3 revenue requirement.

A. Consumers Energy proposes to increase the Customer Charge from $482.00 per month to $568.50 per month and increase the Distribution Charge from $0.9066 per Mcf to $1.0514 per Mcf. These increases were established in order to maintain the economic break even point between Rate GS-2 and Rate GS-3 and provide for recovery of the Rate GS-3 revenue requirement.
Q. Please describe how the Company proposes to set prices to recover the General Service Rate GL revenue requirement.

A. Consumers Energy proposes to maintain the current charge for single mantle fixtures at $16.00 per luminaire and to increase the charge for multiple mantle fixtures from $21.00 to $22.00 per luminaire. At the bottom of Exhibit A-55 (RLP-4), Schedule F-3, Page 6 of 9, I have developed a cost analysis for the two types of fixtures. Based on the Company’s projected gas cost of $7.5280 per Mcf, the monthly cost of gas associated with the multiple fixtures is about $24 per month, which justifies a rate increase. The Company proposes a gradual increase in order to avoid placing an extreme burden on the Rate GL customers.

Proposed rates for the GS-1, GS-2, GS-3 and GL rates are shown on Exhibit A-55 (RLP-4), Schedule F-3, pages 3 through 6.

Transportation Class Proposed Rates

Q. Please describe how the Company proposes to set prices to recover the revenue requirement for the Transportation rate class.

A. Consumers Energy proposes an equal percent increase across the Transportation Service rates, similar to the approach used for Residential and General Service rates. The increase attributed to the Transportation Service class will be spread equally across the Transportation rates ST, LT and XLT.
Q. Please describe how the Company proposes to set prices for the Transportation Service Rate Schedule ST.

A. The Company proposes to increase the Rate ST Customer Charge from $510.00 per month to $631.30 per month and to recover the class’s remaining revenue requirement via a Distribution Charge increase from $0.8135 per Mcf to $0.9734 per Mcf.

Q. Please describe how the Company proposes to set prices for the Transportation Service Rate Schedule LT.

A. Consumers Energy proposes to increase the Rate LT Customer Charge from $2,830.00 per month to $3,481.30 and increase the Distribution Charge from $0.5283 per Mcf to $0.6314 per Mcf.

These increases maintain the economic break even points between Rate ST and Rate LT (100,000 Mcf annually), between Rate LT and Transportation Service Rate XLT (500,000 Mcf annually) and provide for recovery of the Rate LT annual revenue requirement.

Q. Please describe how the Company proposes to set prices for the Rate Schedule XLT.

A. Consumers Energy proposes to increase the Rate XLT Customer Charge from $7,210.00 per month to $8,739.80 per month and increase the Distribution Charge from $0.4178 per Mcf to $0.5035 per Mcf.

These increases maintain the economic break even point between LT and XLT and provide for recovery of the XLT annual revenue requirement. Proposed rates for ST, LT and XLT are shown on pages 7 through 9 of Schedule F-3, Exhibit A-55 (RLP-4).
Q. Is the Company proposing changes to the transportation charge adjustment associated with the Authorized Tolerance Levels?

A. Yes. The Company proposes to modify the transportation charge adjustments by the same percentage that all Transport delivery rates are being increased, 20.6%.

Q. Are you sponsoring any other exhibits regarding the Company’s proposed rate design?

A. Yes. I am also sponsoring Exhibit A-55 (RLP-4), Schedule F-3, Calculation of Test Year September 2010 Current and Proposed Revenues by Rate Schedule. This exhibit provides a comparison of current and proposed revenues by rate schedule. In addition, I am also sponsoring Exhibit A-56 (RLP-5), Schedule F-4, Comparison of Typical Bills under Current and Proposed Rates. This exhibit provides a comparison of the impact of proposed rate increases for sales rates at various usage levels.

RULES AND LANGUAGE CHANGES

Q. Please describe Exhibit A-57 (RLP-6), Summary of Tariff Changes.

A. Exhibit A-57 (RLP-6) details all language and non-rate price changes being proposed to the Company’s Gas Rate Book. A brief explanation for all changes can be found on Exhibit A-57 (RLP-6).

Q. Please explain the proposed change on Tariff Sheet Nos. C-5.00 and C-6.00 to remove the references to the System Supply Entitlement Charge (SSEC).

A. The System Supply Entitlement Charge (SSEC) was removed from the Company’s tariffs in Case No. U-13000 following the Order issued in November 2002. The Company inadvertently failed to remove these obsolete references at that time and is proposing to remove them in this proceeding.
Q. Please explain the change made to Rule C4.3, Application of Residential Usage and Non-Residential Usage.

A. The term “Principal Rate Customer” was defined. This term is used in the Residential Income Assistance Provision and the definition aligns with the Company’s Electric Rate Book.

Q. Please explain the change to Rule C7.2 C. (3)(d) found on Tariff Sheet No. C-33.00.

A. The Company is proposing to revise the “$2.00 or less” reference to “$10.00 or less” in Rule C7.2 C. (3)(d) relating to Non-GCR Refunds for past customers no longer on the Company’s system. This change will align with the “Consumer Standards and Billing Practices for Electric and Gas Residential Service” adopted by the Commission in Case No. U-14851 dated October 26, 2007. The Commission recognized that the threshold for returning a credit balance should be increased to $10 in Rule R 460.118, Equal Monthly Billing, and Rule R 460.126, Billing Error.

Q. Please explain the change made to the Carrying Cost Rate and Discount Rate within the incremental costs of the Customer Attachment Program Rule C8. I. (1) and (6).

A. Both the Carrying Cost Rate and the Discount Rate are based on the weighted rate of debt, preferred stock, equity and associated taxes, which are located on Exhibit A-59 (DVR-1) and Exhibit A-60 (DVR-2). The Carrying Cost Rate is changing from 11.44% to 11.80% and the Discount Rate is changing from 8.12% to 8.39%.

Q. Please explain the change to Rule E1.1 Definitions.

A. “Business Day” has been added as a definition to specifically state that a “business day” means Monday through Friday, excluding Company holidays.
Q. Please explain the change to Rule E2.2 (C), Nominations, Accounting and Control on Tariff Sheet No. E-3.00.
A. The phrase “on the Business Day” has been added to clarify that nominations cannot be made on Saturday, Sunday or Company holidays.

Q. Please explain the change to Rule F1.I, General Provisions.
A. Language has been modified in this rule to reference that nominations must be made as specified in Rule E2.2 (C), Nominations, Accounting and Control on Tariff Sheet No. E-3.00.

Q. Please describe Exhibit A-58 (RLP-7), Schedule F-5, Proposed Tariff Sheets, M.P.S.C. No. 2 – Gas (Redlined Version).
A. Exhibit A-58 (RLP-7) shows all rate and rule changes being proposed by the Company to its Gas Rate Book. Data being deleted is shown by strikeouts while additions are in italics. The rationale for each significant change can be found within my testimony.

Q. Does this conclude your testimony?
A. Yes, it does.
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
distribution of natural gas and for other relief

Case No. U-15986

DIRECT TESTIMONY

OF

DHENUVAKONDA V. RAO

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business address.
A. My name is Dhenuvakonda V. Rao. My business address is One Energy Plaza, Jackson, Michigan, 49201.

Q. By whom are you employed and in what capacity?
A. I am employed by Consumers Energy Company as Executive Director of Financial Forecasting and Planning.

Q. What are your current responsibilities?
A. I am responsible for preparing the monthly forecasts and five year financial plan for Consumers Energy and CMS Energy which are presented to the Board of Directors on a periodic basis. As a part of my role, I also conduct financial analyses and studies required for making various strategic decisions such as equity issuance, sale of businesses and new investments. I also interact with credit rating agencies in analyzing the past financial performance of the Company as well as presenting the future financial trends. In addition, I assist the Chief Financial Officer in preparing the presentations for Board of Directors meetings, quarterly earnings calls, investor meetings, and industry conferences. I also participate in meetings with various banks, equity research analysts and investors as a part of my role.

Q. What is your educational background?
A. I received a Bachelor of Technology degree in Mechanical Engineering from the Indian Institute of Technology, Bombay, India in 1992. I received a Masters in Business Administration degree from the Indian Institute of Management, Lucknow, India in 1995. I am also a Chartered Financial Analyst (CFA), a designation offered by CFA Institute.
(formerly the Association of Investment Management and Research), a global membership organization of investment professionals based in Charlottesville, Virginia.

Q. What positions did you hold prior to your present position?

A. I began my career in 1995 as a credit analyst in the project finance division of ICICI Bank (formerly Industrial Credit and Investment Corporation of India) based in Bombay, India where I worked on financing of projects in various industries including power and telecommunications. In 1999, I joined CMS Energy’s India office as a financial analyst supporting the development of projects in Asia and Australia. In 2000, I was transferred to CMS Enterprises Company in Dearborn, Michigan to be a part of Global Finance group which was later renamed as Financial Advisory and Strategic Planning group. As a part of this group, I conducted financial modeling and risk analysis for various development projects, acquisitions and other value propositions for CMS Enterprises as well as Consumers Energy. In 2003, I became the Director of Financial Advisory and Strategic Planning and handled various restructuring and financial optimization assignments for CMS Enterprises and Consumers Energy. From January 1, 2005 to March 1, 2009, I was the Senior Director of Financial Planning for Consumers Energy. On March 1, 2009 I took over responsibility for the Financial Forecasting and Financial Planning for Consumers Energy.

PURPOSE

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: a) present my recommendations regarding the capital structure and cost of capital which should be used in computing the overall rate of return for Consumers Energy Company’s gas business, b) present my return on equity
recommendation and present an analysis of i) how investors’ perception of risk has changed since Consumers’ last gas rate case and ii) how the financial risk of the Consumers Energy’s gas business compares to the proxy group, c) recommend the utilization level of Consumers Energy’s Accounts Receivable Financing program that should be used for estimating the working capital requirement for Consumers Energy’s gas business, and d) recommend the fee that should be used in computing the cost of Accounts Receivable Financing program for Consumers Energy’s gas business.

Q. How is the remainder of your testimony organized?

A. My testimony is organized as follows:

I. Summary of Recommendations

II. Capital Structure and Cost Rates
   A. Development of Capital Structure
   B. Development of Cost Rates

III. Development of Return on Equity Recommendation
   A. Summary of ROE Results
   B. General Principles
   C. Development of Common Equity Cost Rate
      1. Selection of Proxy Companies
      2. Capital Asset Pricing Model Analysis
      3. Risk Premium Analysis
      4. Discounted Cash Flow Analysis
   D. Financial Risk Comparisons
      1. Proxy Group Risk Comparison
      2. Risk comparison vs. prior case
   E. ROE Summary and Conclusions

IV. Accounts Receivable Financing
   A. Accounts Receivable Financing Program Utilization
   B. Accounts Receivable Financing Program Costs

V. Exhibits for Certain New Filing Requirements – (Current and Historical Credit Ratings and Recent Utility Bond Issuances)

VI. Summary and Conclusions
Q. Are you sponsoring any exhibits?
A. Yes. I am sponsoring the following exhibits:

- Exhibit A-59 (DVR-1) Schedule D1, Overall Rate of Return Summary
- Exhibit A-60 (DVR-2) Capital Structure Development
- Exhibit A-61 (DVR-3) Comparison of Development of Capital Structure on a Financial versus MPSC Ratemaking Basis
- Exhibit A-62 (DVR-4) Schedule D2, Cost of Long Term Debt
- Exhibit A-63 (DVR-5) Average DOE Liability Balance
- Exhibit A-64 (DVR-6) Schedule D3, Cost of Short Term Debt
- Exhibit A-65 (DVR-7) Schedule D4, Cost of Preferred Stock
- Exhibit A-67 (DVR-9) Financial Risk Analysis
- Exhibit A-68 (DVR-10) Schedule D5, Return on Equity Recommendation
- Exhibit A-69 (DVR-11) Current and Historical Credit Ratings
- Exhibit A-70 (DVR-12) Recent Utility Corporate Bond Issuances

Q. Were these exhibits prepared by you or under your direction or supervision?
A. Yes.

I. SUMMARY OF RECOMMENDATIONS

Q. Can you provide an overview of the current state of the capital markets and how they impacted your overall analysis?
A. Global capital markets have experienced dramatic changes over the past couple of years.

In today’s capital markets, the supply and demand imbalance for capital has resulted in
less liquidity and significant increases in the pricing of risk and the cost of capital. These
challenges are compounded by the downturn in the economy and specifically in the
economic challenges in Michigan. Companies are competing for this limited amount of
capital and overall capital costs have increased as I will discuss further in my testimony.
Additionally, utilities are more dependent on the capital markets than many other
industries in order to fund their capital intensive operations. In addition, the cost of short-
term credit facilities (revolvers and letter of credit facilities) has increased significantly in
the current market place.

Though the Company has navigated prudently through these tough economic
times, the Company has not been immune to the challenges. Consumers Energy has
experienced higher borrowing costs as evidenced by our recent First Mortgage Bond
(FMB) issuance and the borrowing capacity under our accounts receivable sales program
has been reduced. I have factored the economic impact and current state of the capital
markets into my cost of capital and return on equity recommendations in this case. In
order to serve our customers and help grow the Michigan economy going forward, it is
critical that rates be set at a level which allows Consumers Energy to attract the capital
needed to run our business, assure investor confidence in the financial soundness of the
utility business, and to operate the business. Consumers Energy’s gas business must be
allowed the opportunity to earn a sufficient return on its investments in this environment
of increasing competition for capital resources. My recommendations take these factors
into account and are designed to provide Consumers Energy an opportunity to earn an
overall return that will allow it to meets the capital costs of its gas utility business,
including a reasonable opportunity to earn a return on equity which is commensurate with returns on investments that have corresponding risks.

Q. What capital structure are you recommending be utilized in the overall rate of return calculation?

A. I am recommending that the capital structure shown on Exhibit A-59 (DVR-1) be used in this case. This represents the actual capital structure as of December 31, 2008 adjusted for the projected changes in debt and equity through the end of the test year ending on September 30, 2010. The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 48.34%. The equity ratio on ratemaking basis is 41.08%.

Q. What return on equity are you recommending for Consumers Energy’s gas business?

A. I am recommending that Return on Equity for Consumers Energy’s gas business be set at not less than 11.00%, assuming that the uncollectable tracker and decoupling mechanism being requested by the Company in this case are approved by the Commission. I have arrived at this recommendation after considering multiple factors including the current state of economy and capital markets, the need to continue to attract capital during the current economic situation, risk profile of the Consumers Energy’s gas business compared to the proxy group, established principles for setting a fair return on equity and results of various economic models used to calculate the cost of equity. These are described in detail in Section III. If the Commission does not approve the decoupling mechanism and uncollectable trackers requested by the Company, the Return on Equity should be higher than 11% to reflect added risk.
Q. What is the overall rate of return for Consumers Energy that you recommend be used in this case?

A. I am recommending an overall rate of return of 7.28% on an after tax basis. This overall rate of return is the result of combining the capital structure and cost rates shown on Exhibit A-59 (DVR-1). The cost of the components and the weighted cost are shown in columns (e) through (h). The overall rate of return that I am recommending is the weighted cost of the various components of the capital structure.

II. CAPITAL STRUCTURE AND COST RATES

Q. What is the purpose of this section of your testimony?

A. The purpose of this section of my testimony is to present the capital structure and cost of capital which should be used in computing the overall rate of return for ratemaking purposes to set just and reasonable rates for Consumers Energy Company’s gas business.

A. Development of Capital Structure

Q. What is your capital structure recommendation?

A. The recommended capital structure is shown on my summary exhibit, Exhibit A-59 (DVR-1). The equity ratio as a percentage of permanent capital is 48.34%. The equity ratio on ratemaking basis is 41.08%.

Q. How did you develop the long term debt and common equity balances in the capital structure?

A. I started with the actual balances of long term debt, preferred stock and common equity as of December 31, 2008 as shown in lines 1 through 3 in column (e-1), page 1 of Exhibit A-60 (DVR-2). I then made the adjustments shown in column (e-2) to arrive at the test
year ending September 30, 2010 balances in column (f) that I am recommending be used in this case.

Q. Why did you not use the 13 month average capital structure as of December 31, 2008?
A. Using the 13-month average for the year ended December 31, 2008 would not accurately reflect the capital structure that will be in effect during 2009 and 2010. Using balances as of December 31, 2008 as the starting point with adjustments for known and measurable changes is more representative of the capital structure that will be in effect during the test year ending September 30, 2010.

Q. Please explain the common equity adjustment of $241 million.
A. The common equity adjustment of $241 million consists of two components. The first is an adjustment to reflect $91 million for retained earnings for the period from December 31, 2008 through the September 30, 2010. The second is an adjustment of $150 million to reflect the average of projected equity infusions in 2009 and 2010.

Q. Please explain the retained earnings adjustment of $91 million.
A. Since I started with the December 31, 2008 balance for the common equity, it was necessary to make an adjustment to reflect the increase in common equity balance through retained earnings that will occur subsequent to December 31, 2008. Consumers Energy has a long-standing policy of using an 80% dividend payout ratio. In calculating the retained earnings, I assumed Consumers Energy’s retained earnings rate to be $6.067 million per month or $72.8 million per year. Failure to reflect retained earnings would understate the common equity balance for the test year.
Q. Please explain how you arrived at the Consumers Energy’s retained earnings rate of $72.8 million per year.

A. Based on Consumers’ 10-K for 2008, I determined that Consumers Energy’s net income for the 12 month period ending December 31, 2008 was $364 million. I used this amount as a proxy for the future net income and assumed a dividend payout ratio of 80%. Using these assumptions, I calculated an annual retained earnings amount of $72.8 million ($364 * (1-0.80)). Exhibit A-60 (DVR-2), page 2 shows the projected monthly retained earnings balance and calculates the 13 month average for the period ending September 30, 2010.

Q. Why did you make a $150 million adjustment for new equity infusions in your recommended capital structure?

A. Consumers Energy has a goal of maintaining a capital structure with a common equity ratio as a percentage of permanent capital of approximately 50%. This is a goal shared by CMS Energy, Consumers Energy’s parent company. The commitment to this goal is illustrated by the equity infusions that have been made over the past several years. CMS Energy plans to make an equity investment of $100 million into Consumers in October 2009 and plans to make an equity investment of $250 million in July 2010. I pro-rated the 2009 contribution for 12 months and the 2010 contribution amount for 3 months of the year and reflected an increase of $150 million to arrive at the projected 13-month average equity capital for the 13 month period ending September 30, 2010. When this adjustment is combined with the $91 million retained earnings adjustment, the increase to equity capital is the $241 million shown on Exhibit A-60 (DVR-2).
Q. Please identify some of the more recent equity infusions.

A. CMS Energy has made the following equity infusions over the past six years:

- 2007 - $650 million
- 2006 - $200 million
- 2005 - $700 million
- 2004 - $250 million

Q. How confident are you that the planned equity infusions of $100 and $250 million by CMS Energy will occur?

A. I am reasonably confident that the planned equity infusions of $100 and $250 million will occur. As I noted previously, the management of CMS Energy and Consumers Energy are committed to maintaining Consumers Energy’s average equity ratio of approximately 50% as a percentage of permanent capital. CMS Energy invested $1.8 billion as common equity into Consumers over the last six years in order to improve Consumers’ financial health and improve the balance sheet to the current long term debt to equity level of approximately 50/50. During the projected test year, even after considering the proposed equity contributions of $100 million and $250 million, I have projected that the equity ratio as a percentage of permanent capital will be slightly lower than 50%, mainly because of the larger debt issue planned in 2009 in order to enhance liquidity and protect against the unprecedented meltdown of the financial markets, as described later in my testimony. The Company plans to revert to 50% equity ratio as the financial markets stabilize.
Q. Why is it important for Consumers Energy to maintain a common equity ratio of approximately 50% as a percentage of its permanent capital?

A. It is important to have a reasonable common equity ratio in order to maintain a strong balance sheet and strong investment grade credit rating. Having a strong investment grade rating is essential for the Company to efficiently raise the capital required to maintain its operating systems and assure reliable service to customers. The importance of credit ratings is particularly felt during the periods of credit crunch like we are currently in, when the low quality borrowers find it extremely difficult to issue new debt and the availability of capital becomes an issue, leave alone the cost. As seen on page 4 of Exhibit A-60 (DVR-2), the proxy group is expected to have an average equity ratio of over 50%. In the current environment, an equity ratio higher than 50% is desirable in a gas utility capital structure as reflected by the proxy companies.

Q. Please explain the long term debt adjustment of positive $175 million.

A. I have projected that the average debt balance for test year ending September 30, 2010 will be $175 million higher than the December 31, 2008 balance. This adjustment consists of four components:

- Increase of $500 million to reflect the debt issued by the Company in March 2009,
- Decrease of $658 million to reflect the retirements of February 2009 debt maturity of $200 million, August 2009 maturity of $150 million, May 2010 maturity of $250 million, and two June 2010 PCRB maturities totaling $58 million.
- Increase of $300 million to reflect the new debt planned to be issued in April 2010
- Increase of $0.5 million in the Company’s liability to Department of Energy (“DOE”) to project the DOE liability for the test year ending September 30, 2010.
The above adjustments total to $175 million on a 13 month average basis for the test year. The development of the 13-month average long-term debt balance is shown on Exhibit A-60 (DVR-2), page 3.

Q. Please describe the purpose of $500 million debt issued in March 2009.

A. Part of the proceeds from this issuance will be used to pay off $150 million maturity due in August of 2009, the remaining amount of $350 million will be used, among other things, for meeting the cash contribution to the Company’s pension plan and enhancing the Company’s liquidity position. The Company anticipates making a cash contribution to the pension plan in 2009 of around $200-300 million in order to offset the decline in the value of the pension assets caused by the recent stock market decline. Accordingly, I have considered it as a cash outflow in 2009 in projecting the total financial needs of the Company. This is consistent with the testimony of the Company witnesses Mr. Herbert Kops and Mr. Daniel Alfred, who have considered this contribution in projecting the pension expense and rate base respectively. With the above plans, I expect the Company to be positioned to finance its operations and investment program so that it can continue to provide safe and reliable service to its customers.

Q. Please describe the planned debt issuance in 2010.

A. The debt issued in 2010 will be used to refinance 2010 debt maturities.

Q. Why did you adjust the DOE liability amount?

A. The DOE liability amount reflects the use by the Company of funds that the Company owes to the DOE for pre-April 1983 Spent Nuclear Fuel (SNF) disposal costs. The DOE liability amount will continue to accrue interest until the amount is paid to the DOE. The projected DOE liability which I have used in the development of the long term debt
represents a 13-month average for the test year ending September 30, 2010. The DOE
liability as of December 31, 2008 was $162.6 million. The amount shown on line 18,
Exhibit A-62 (DVR-4) was calculated by adjusting the December 31, 2008 DOE Liability
balance of $162.6 million using the forecast 91-day treasury rates for 2009 and 2010 as
shown on Exhibit A-63 (DVR-5). This calculation resulted in a $0.5 million increase to
the DOE liability. The projected liability of $163.1 million which I have used in
developing the capital structure is consistent with the DOE liability amount included in
rate base for this case.

Q. What is your expectation regarding the level of short-term debt balance for the test year
ending September 30, 2010?
A. Exhibit A-66 (DVR-8) shows the projected monthly balances of short term debt for the
test year ending September 2010. I have arrived at these projections after considering the
projected total monthly cash flow requirements, planned long term debt (net) and equity
issuances and the amount of accounts receivable financing available. The average balance
of short term debt for the test year is $55.8 million. The profile of monthly balances is
consistent with the historical trend where the Company borrows on short term facilities
during fall and winter months and no short term funding is required during summer
months. Accounts receivable financing is discussed further later in my testimony. I have
projected that during 2009 and the first nine months of 2010 the Company will use
Accounts Receivable financing sources before it draws on the revolving credit facility.

Q. How did you estimate the Deferred Tax Balance for the test year?
A. I used the 13 month average deferred tax balance as of December 31, 2008 of $1,263
million.
Q. What balances did you use for JDITC in the proposed capital structure?
A. I allocated the components for Job Development Investment Tax Credit (“JDITC”) based upon the allocation of long term debt and common equity.

Q. Why are you not recommending the use of 13-month average amounts as of December 31, 2008 for common equity and long term debt?
A. The 13-month average common equity amount as of December 2008 does not reflect the growth resulting from retained equity earnings subsequent to December 2008 or the planned equity infusions in 2009 and 2010. Using the 13-month average would understate the average equity balance for the test year ending September 30, 2010. Using the December 2008 balance also would not reflect the changes in the long term debt schedule. Therefore, I began with the actual balances as of December 2008 and adjusted for the projected changes in order to arrive at representative 13 month averages for the test year ending September 30, 2010.

Q. Are there differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis?
A. Yes. For example, capitalized leases and the effect of FAS 115 would be included in determining capital structure on a financial basis. They are excluded in determining a capital structure on a ratemaking basis. Also, on a ratemaking basis deferred ITC, deferred income taxes and deferred JDITC would be included. Differences are listed on Exhibit A-61 (DVR-3).
B. Development of Cost Rates

Q. Please explain the development of the total weighted cost of capital shown on Exhibit A-59 (DVR-1), column (g), line 12.

A. Column (d) represents the percentage of total capital provided by each of the components of the capital structure shown in column (a). These percentages were developed by dividing the amounts of capital shown in column (b) by the total ratemaking capitalization amount shown in column (b) line 12. Column (e) presents the costs, on a ratemaking basis, of each of the components in total ratemaking capitalization. Column (g) is the after-tax weighted cost of capital and is calculated by multiplying column (d) times column (e). The pre-tax weighted cost is shown in column (h).

Long Term Debt Cost Rate

Q. What long term debt annual cost rate did you use in this case?

A. I developed a 5.97% annual cost for long term debt. The development of this annual cost rate is shown on Exhibit A-62 (DVR-4). Consistent with past Commission practice, the costs are determined on a net proceeds basis. I began with the debt issuances outstanding as of December 31, 2008 and excluded the 2009 and 2010 maturities. Then, I added the new debt issuances mentioned earlier in my testimony. These are shown on lines 11 and 12. Line 11 represents the new debt of $500 million issued in March 2009. Line 12 represents a new debt issuance of $300 million planned for April 2010, as mentioned earlier in my testimony.

Q. Why did you use cost on a net proceeds basis?

A. Not reflecting costs on a net proceeds basis would understate costs. The net proceeds methodology accounts for underwriters’ compensation and finance expense. The fees
and expenses are shown as a reduction in proceeds from the issuance of new securities, thereby increasing the cost of the issuance over the stated coupon rate.

Q. Please explain the cost rate you used on Line 11 of Exhibit A-62 (DVR-4) for the new fixed rate debt issuance of $500 million in March 2009.

A. The new fixed rate debt issuance of $500 million issued in March 2009 was issued at a coupon rate of 6.70% and a cost based on net proceeds of 6.80%. The bond issue involved a credit spread of 380 basis points over the corresponding U.S. treasury rate.

Q. Please explain the cost rate you assumed for planned debt issuance in 2010 of $300 million shown on Line 12 of Exhibit A-62 (DVR-4).

A. I assumed the 2010 debt issuance will be a 10 year fixed rate bond. Based on current treasury rate projections and credit spread volatility, I believe that our March 2009 issue provides the best proxy for this debt. I projected a coupon rate of 6.70% and a cost based on net proceeds of 6.80%.

Q. Are there any existing long term debt issuances that have variable rates?

A. Yes. There are three debt issuances shown on Exhibit A-62 (DVR-4) that have variable interest rates. These are the PCRB issuances shown on lines 14 and 15 and the DOE liability shown on line 18.

Q. What cost rates have you used for the variable rate issuances shown on Exhibit A-62 (DVR-4)?

A. The first two long term debt issuances which have variable interest rates are shown in Line 14 and 15 of Exhibit A-62 (DVR-4). Historical data indicates that the interest rate on PCRBs is approximately 70% of the cost of 3 month LIBOR. Accordingly, I used 70% of projected 3 month LIBOR rate for the test year ending September 30, 2010 to
estimate the cost of PCRBS. I used an average of the projected 3 month LIBOR rates from Global Insight (February 2009 Edition) and Blup Chip Forecasts (March 2009 Edition) to determine a projected LIBOR rate of 1.60%. The estimated interest rate on PCRBS is 1.12% (0.70 * 1.60%). Since the interest rate on the Company’s DOE liability is linked to the 91-day T-bill rate, I used a cost rate of 0.55%. This is the average of the 0.5475% projected by Global Insight (February 2009 forecast) and 0.55% projected by Blue Chip (March 2009 forecast) for the 91-day T-bill rate for the test year.

Q. Please explain line 20 on Exhibit A-62 (DVR-4).

A. Line 20 on Exhibit A-62 (DVR-4) represents the amortization of losses on reacquired Consumers debt (including call premium) for refinancings done prior to 2006. This amortization needs to be added to the interest cost on the refinanced debt to determine Consumers Energy’s true financing cost for the long term debt.

Q. What does the amortization of losses on reacquired debt represent?

A. When Consumers refinances a higher cost debt with a lower cost debt, the Company will typically pay what is referred to as a “call premium” to do so. The call premium and any unamortized costs on the original debt are recorded as an asset and amortized over the life of the new debt. This amortization plus the interest cost on the new debt represents Consumers Energy’s true financing cost for the new long term debt. The Commission recognized recoverability of these costs in establishing the cost rate in cases U-14347 and U-14547. It is important to recognize that the amortization is not a single year event but continues for the life of new debt.
Q. What would be the effect of not including the amortization of loss on reacquired debt?

A. Not including the amortization of losses on reacquired debt would mean that the customers get the benefit of lower cost debt obtained by the Company but do not share the cost incurred by the Company in obtaining the lower cost of debt. This would be unfair and inconsistent with the Commission’s past practice. Customers benefit from the lower cost of debt and should pay the cost for amortization of losses on reacquired debt that allowed the Company to obtain the lower cost debt.

Q. How did you calculate the amount shown on Line 20?

A. The amount shown on Line 20 of $8,540,000 was based on the projected amortization expense during the 12 month period ended September 30, 2010.

Q. Please explain Lines 21a and 21b on Exhibit A-62 (DVR-4).

A. Lines 21a and 21b on Exhibit A-62 (DVR-4) represent the annual cost of issuing the letters of credit provided by the Company to Entergy pursuant to the Palisades sale transaction. Line 21a reflects fees for a $163 million letter of credit which allows Consumers Energy to retain use of the DOE liability funds by providing assurance of fund availability until paid to the DOE. Line 21b reflects fees for a $30 million letter of credit related to the Palisades power purchase obligations. These letters of credit are provided under a letter of credit facility the Company has obtained from Bank of Nova Scotia. The cost of providing letter of credit until November 2009 is 115 basis points per an agreement signed by the Company with Bank of Nova Scotia in September 2008. However, the rate is expected to increase to at least 250 basis points upon renewal in 2009. Using a projected spread of 250 basis points, I have calculated annual fees associated with the DOE liability letter of credit of $4.075 million and annual fees
associated with the Palisades PPA letter of credit of $0.750 million. Based on this, the
annual cost combined is $4.825 million ($193 million * 0.0250).

Q. The Commission excluded fees related to the DOE liability letter of credit in its order in
Case No. U-15245. Why do you believe the above letter of credit costs should be
recoverable from customers in the current case?

A. I believe the $4.075 million annual cost for the $163 million letter of credit pertaining to
the DOE liability should be recoverable from ratepayers since it enables the Company to
continue to retain, for the benefit of customers, the DOE liability which is a low cost
source of funds included in the Company’s long term debt portion of the capital structure.
In the absence of this letter of credit, Consumers Energy would not have been able to
keep this low cost source of funding.

Q. How do the annual cost for the DOE liability plus the annual cost for the letter of credit
compare to alternative sources of long-term debt?

A. The annual cost for the DOE liability plus the annual cost for the letter of credit
combined is less than what customers would pay if the Company had to obtain another
long term debt source for this funding. The annual costs combined are equivalent to a
cost based on net proceeds rate of 3.05% for the DOE liability for the projected test year
(projected 91-day Treasury rate of 0.55% plus Letter of Credit cost of 2.50%). This
compares to a projected long term debt rate for the Company on a net proceeds of 6.70%
in 2010. The annual letter of credit fee is a cost which should be recoverable from
customers. The Commission through its ratemaking treatment of including the DOE
liability amount in the long term debt calculation has recognized that use of these funds
prior to payment to the DOE benefits customers. The letter of credit allows Consumers
Energy to continue using these funds. In order to maintain the letter of credit, payment of the annual fees is necessary. The cost of this financing source, including the fee, is less expensive than the cost would be for new long-term debt.

Q. Why was the DOE liability Letter of Credit necessary for the Palisades sale?

A. Section 6.13 of the Asset Sale Agreement for sale of the Palisades Plant stated:

"Before the Closing and at all times thereafter, Seller [Consumers Energy] shall remain liable for, and pay as they come due, all Spent Nuclear Fuel Fees attributable to electricity generated at Palisades and at the Big Rock Point Plan Operating Facility and sold prior to the Closing, including the Pre-1983 Fee, and Buyer shall have no Liability or responsibility therefor. Buyer shall be liable for all Spent Nuclear Fuel Fees attributable to electricity generated at Palisades and sold after the Closing, and Seller shall have no Liability of responsibility therefor."

Entergy Nuclear Palisades, LLC required assurance that the amount owed by Consumers to the DOE for spent nuclear fuel disposal under the federal Nuclear Waste Policy Act of 1982 would be paid when due since this is considered a prerequisite to the DOE taking possession of spent nuclear fuel from the Palisades and Big Rock sites. Section 6.14(g) of the Asset Sale Agreement stated:

"Seller shall deliver to Buyer at the Closing security in respect of Seller’s obligation to pay the Pre-1983 Fee in the form of cash, letter(s) of credit, or other security reasonably acceptable to Buyer in an amount not less than the then-outstanding amount of the Pre-1983 Fee (such cash, letter of credit or security to be adjusted not less than annually to reflect changes in the amount of the Pre-1983 Fee due). . ."

The annual letter of credit fee is a cost of maintaining the letter of credit.
Q. Is the DOE liability obligation which is the subject of this letter of credit a result of the DOE’s longstanding failure to take possession of spent nuclear fuel?

A. No. This letter of credit relates to the payment of the fee mandated by the Nuclear Waste Policy Act of 1982 for nuclear fuel burned prior to April 7, 1983. The Asset Sale Agreement defined the term “Pre-1983 Fee” in the following way:

“‘Pre-1983 Fee’ means the one-time fee, including any interest, late fees and/or penalties accruing thereon from time to time, payable by Seller pursuant to Article VIII(B)(2) of the Standard Spent Fuel Disposal Contract.”

The Standard Spent Fuel Disposal Contract refers to the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste entered into in 1983 between Consumers and the United States of America, represented by the Department of Energy. The annual letter of credit fee is a reasonable cost for maintaining the ability to use the funds owed to the Department of Energy and benefits customers.

Q. Why did you include the cost of the above letters of credit in the long term debt cost?

A. As explained earlier, the Letter of Credit related to DOE liability enables the Company to retain the use of low cost DOE liability, which is treated as a part of long term debt. Therefore, the Letter of Credit fee is also included under the long term debt cost. The Letter of Credit related to the Palisades PPA enables the Company to avoid prepayments to Entergy. In the absence of the Letter of Credit, the Company will incur additional interest expense due to prepayment of power purchase costs, which will be more expensive than the fee paid to obtain the Letter of Credit. Thus, the Letter of Credit is a substitute for avoided interest expense and is appropriate to be treated as financing cost.
Q. Please explain Line 22 – PCRB Fees shown on Exhibit A-62 (DVR-4).

A. Consumers Energy incurs certain on-going fees to maintain our PCRB debt securities which are included in the long term debt for ratemaking purposes. These fees include (i) ongoing bond remarketing expense and the trustee expense and (ii) the cost of letters of credit required under the bond agreements. I have included $123,000 for the first expense based on actual experience and $488,000 for the costs of the PCRB letters of credit. Historically, the Company incurred the cost of an insurance premium to obtain the required insurance from monoline bond insurers. However, since the refinancing in 2008, the Company is required to provide Letters of Credit pursuant to the bond agreements and incurs a cost to do the same. I calculated the cost of $488,000 based on the letter of credit amount of $103 million and the cost of 47.5 basis points. These letters of credit are provided under the existing Revolver which has a credit spread of 35 basis points and a fronting fee of 12.5 basis points. Since the terms of existing revolver are valid until 2012, I do not expect the cost rate to change in the test year. These fees are prudent, reasonable, and customary for these types of tax-exempt securities and I believe are properly recoverable from ratepayers.

Q. Were these costs included in the development of the cost based on net proceeds for the PCRB issuances shown in Lines 14 through 15?

A. No. These costs were not incurred at inception of these securities, but rather are incurred on an on-going basis over the life of these securities. Consequently they are not included in the net proceeds calculation and are shown separately.
Short Term Debt Cost Rate

Q. What short-term debt cost rate did you use in this case?

A. I used an 8.83% cost rate for short-term debt based on the projected cost of borrowing under the Company’s revolving credit facility.

Q. Please explain the cost of borrowing under the revolving credit facility.

A. There are two types of costs incurred by the Company for the amounts borrowed under the revolving credit facility. The first is the interest expense, which is calculated on the drawn balances at a rate equal to the base rate (specified as London Interbank Offered Rate or LIBOR) plus the applicable spread (currently at 35 basis points). The second type of cost is the Revolver Fees.

Q. Please describe the Revolver Fees.

A. The Revolver Fees consist of two parts:

1) Annual Revolver Fees – This cost consists of Annual Revolver Commitment Fees, which the Company is required to pay quarterly to the banks on the “unused” portion of the revolver, and other required annual fees under the Revolving Credit agreement. The Revolver Commitment fees are associated with maintaining fund availability.

2) Amortization of Upfront Revolver Fees – At the inception of a revolving credit facility, the borrower is required to pay upfront fees and issuance costs to the lenders. These issuance and upfront costs are amortized over the life of the revolver.

These fees and costs are customary in revolving credit agreements. It is important to allow for the recovery of revolver fees in addition to the interest expense since these are
necessary costs to secure the availability of the financing and to keep the facility available for the financing needs of the Company. The revolving credit facility is the primary source of Company’s liquidity. The Company cannot avoid incurring these costs except by giving up the revolving credit facility, which would not be a sound business decision. If these fees are not recovered through short-term debt cost then they need to be recovered as part of long-term debt cost.

Q. How has the Commission treated these Revolver Fees in the past in Consumers Energy’s recent rate cases?

A. The Commission allowed the recovery of these costs by adding an additional spread of 25 basis points to the cost of short-term debt in Case U-14547 and 54 basis points in Case U-14347, in addition to the interest rate spread.

Q. How did you arrive at the project cost rate for the test year?

A. Exhibit A-64 (DVR-6) shows the projected cost rate for borrowings under the revolver. On Line 1, I have projected the base rate (i.e. LIBOR) to be 1.60%. On Line 2, I added the revolver interest rate spread of 0.35%. On Line 3, I estimated the Revolver Fees to be 6.88%. The sum of these three items results in a total rate of 8.83%.

Q. How did you estimate the Revolver Fees of 6.88%?

A. As shown at the bottom of Exhibit A-64 (DVR-6), I projected the Total Revolver Fees for the test year to be $3,841,000. I then divided this by the projected short term debt balance of $55.8 million to arrive at a rate of 6.88%. The Total Revolver Fees projected for the test year is comprised of projected fees on our $500 million revolver of $841,000 and an additional fee of $3,000,000 related to the $150 million supplemental revolver obtained by the Company in September 2008, which is subject to renewal in September.
2009. The cost of short-term debt of 8.83% represents the cost to provide $650 million of needed liquidity to Consumers Energy. It appears high due to the level of average borrowings. The projected revolver fees and amortization of $3.8 million, however, are at a reasonable level to provide for access to $650 million of credit.

Q. Please explain the supplemental revolver obtained by the Company in September 2008.

A. The Company currently has $500 million of revolving credit facility which is valid through 2012. Out of this facility, the Company has utilized approximately $103 million to provide Letters of Credit to secure Pollution Control Bonds refinanced in early 2008, as explained earlier in my testimony. This leaves only $397 million of revolver capacity available to meet the normal working capital requirement. The Company therefore decided to obtain a supplemental revolving credit facility of $150 million to supplement the original revolver and provide additional liquidity of approximately $50 million to meet any unexpected rise in gas prices.

Q. Please explain why the cost of the supplemental revolving credit facility is expected to increase?

A. Banks have increased significantly the cost of short-term credit facilities. Banks have less capital available to lend and are accordingly pricing facilities much higher than in the past. For this supplemental $150 million revolving credit facility we anticipate the annual price to be at least 200 basis points. If Consumers Energy is going to maintain the revolving credit facilities, then the revolver fees and revolver amortization are unavoidable. These fees are required by financial institutions in order to provide credit and are increasing in light of the current economy and the current tightening of credit.
Q. Would it be reasonable for Consumers Energy to reduce the available credit which is available under the Revolving Credit Agreement to something less than $650 million?

A. Definitely not. It is important that Consumers Energy have ready access to credit if the need arises for additional funds. Internal cash generation is not sufficient to meet the Company’s liquidity needs. Credit has become increasingly difficult to access in the current environment. Michigan’s economy remains weak. Recent announcements by automakers of cutbacks, and ripple effects, create additional risks for Consumers Energy. These factors add uncertainties for Consumers Energy’s gas business and provide added support for the importance of maintaining access to an adequate credit line. Not maintaining access to the revolving credit facility would put Consumers Energy and its customers at risk.

**Preferred Stock Cost Rate**

Q. What is the annual cost of Preferred Stock?

A. The annual cost of Preferred Stock is shown on Exhibit A-65 (DVR-7). This cost is 4.46% and is the same as the historical cost rate.

**Common Equity Cost Rate**

Q. What rate did you use for the cost of common equity?

A. I used a cost rate of 11.00% for the common equity based on the analysis I performed. This analysis is discussed later in section III of my testimony.

Q. If long term debt is less expensive why not raise the Company’s capital needs only with debt?

A. While a capital structure with more debt might appear to provide an opportunity to lower overall cost of capital, a large amount of debt in the capital structure reduces the credit
quality of the debt. This in turn leads lenders to demand higher interest rates and restrictive covenants limiting the borrower’s access to capital. Therefore, it is important to maintain a balance of debt and equity.

**Other Cost Rates**

Q. What cost rates did you use for the remaining components of the capital structure?

A. I used a cost rate of 7.00% for Customer Deposits and a cost rate of 7.33% for Other Interest Bearing Accounts. Also, Consistent with MPSC ratemaking practice, deferred income taxes and deferred investment tax credit (net of JDITC) are included at zero cost. The cost rates for each of the three components of JDITC correspond to the cost rates for long term debt, preferred stock, and common equity.

**III. RETURN ON EQUITY RECOMMENDATION**

A. **Summary of Roe Results**

Q. Can you summarize your findings regarding Consumers’ cost of common equity?

A. I have examined the risks of Consumers Energy and have determined that the risk level is above the both industry average and the average for the proxy group I used in my analyses. The difficult economic climate in Michigan and the turmoil in the credit markets are significant drivers impacting Consumers Energy’s investor-perceived risk. My analysis included an assessment of the market and risk environment for the company along with four return methodologies: 1) Capital Asset Pricing Model “CAPM”, 2) Risk Premium, 3) Discounted Cash Flow “DCF”, and 4) Value Line Book Value ROE method. The results of my return on equity analyses are summarized on page 10 of Exhibit A-68 (DVR-10). Based on my analysis, I have recommended a return on equity range of 10.75-11.25%. The results of my analyses support a conclusion that the Commission
should set rates in this case which allow Consumers Energy’s a reasonable opportunity to
earn a return on common equity for its gas business of not less than 11.00%.

The company has filed for an uncollectable expense tracker and a decoupling
mechanism in this case and I have assumed that these mechanisms will be approved in
this case in determining my return on equity recommendation. If these mechanisms are
not approved in this case I would recommend a higher return on equity recommendation.
All of the proxy group companies I have analyzed already have decoupling mechanisms
in place as shown in Exhibit A-68 (DVR-10), page 1. Not having a volumetric risk
reduction measure for Consumers Energy makes the Company even more risky than the
proxy group.

Q. How has the recent financial and economic turmoil effected investor expectations and
return requirements?

A. There is less availability and liquidity in the marketplace, which has resulted in
significant increases in the pricing of risk and cost of capital. It is clear that the
competition for capital is fierce and investors are demanding more for their investment
dollar. While lower treasury rates partially offset the risk premium increase, the spreads
being required have increased and the overall results suggest that capital costs have
significantly increased. I have considered these factors in my analysis.

B. **General Principles**

Q. What are the general principles in setting a fair rate of return?

A. The basic principles essentially mirror those that normally apply to non-regulated
companies. The investment community determines the market price of financial
securities such that the anticipated returns compensate the investor for the overall
perceived risk of the specific security. For regulated companies, the Hope and Bluefield Supreme Court decisions have established the framework upon which a company’s fair rate of return may be determined.

Q. Please explain why you view these cases as significant.

A. Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia, 262 U.S. 679 (1923), stated that equity investors are entitled to a return commensurate with investments of comparable risk, that earnings must be sufficient to assure financial soundness of the utility, and that a utility must be able to earn a return sufficient to support its credit and raise required capital. In Federal Power Commission v Hope Natural Gas Company, 320 U.S. 591 (1944), the court again stated that the return be set at a level such that a utility is able to attract capital sufficient to maintain its financial integrity and overall credit position. These principles are reflected in the return on equity analyses I discuss in my testimony.

Q. Why did you employ different methodologies for your presentation in this case?

A. Although methodologies as the CAPM, Risk Premium, and DCF are often used in utility cost of capital determinations, each one by itself is unlikely to perfectly simulate the operations of the market. Accordingly, the application of multiple methods combined with an overall assessment of the marketplace is appropriate in evaluating the market-required cost rate for common equity capital.
C. Development of Common Equity Cost Rate

1. Selection of Proxy Companies

Q. Why did you select a group of proxy companies to perform your analyses?

A. Since the common stock of Consumers Energy is not publicly traded, it is necessary to use indirect or proxy approaches to calculate an appropriate ROE.

Q. Please describe how you chose your proxy group of companies.

A. The focus of this case is on Consumers Energy’s gas operations. My initial selection criteria were to identify gas utility companies that are publicly traded and for which public data is available. Based on this, my initial proxy group consisted of the companies that are currently classified as gas utility companies by the Value Line Investment Survey (“Value Line”). Then, in addition, the company had to: i) be paying current common stock dividends, ii) 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”), iii) have approximately 40% or more of its operating revenues from gas operations. These additional criteria reduced the initial group to 9 companies. The list of my proxy group companies is found on page 1 Exhibit A-68 (DVR–10). I believe this group of 9 companies is representative of the industry as a whole and provides a proxy for gas utility companies that can be used in evaluating an appropriate return on equity for Consumers Energy’s gas business.

Q. Did you review any other companies in course of your analysis?

A. Yes. While I did not include CMS Energy in the proxy group, I undertook a CAPM analysis and a DCF analysis on CMS Energy.
2. **Capital Asset Pricing Model Analysis**

Q. Please describe the CAPM approach.

A. The CAPM is a simple model that describes the expected rate of return on any security or portfolio of securities. The CAPM was first developed in the 1960s by William F. Sharpe, John Lintner and Jack Treynor and is one of the most widely used techniques to estimate the cost of equity. The principal insight of the CAPM is that the expected return on an asset is related to risk; that is, risk-taking is rewarded. The CAPM states that the expected rate of return on an investment is equal to a risk-free rate of return plus a risk premium. The size of the risk premium for an investment is dependent on the amount of unavoidable (or systematic) risk taken. An investment’s systematic risk is obtained by the application of a beta, which is an indication of the relative risk of an investment to the risk of a market portfolio consisting of all risky assets.

Q. Would you please be more specific as to the theory underlying CAPM?

A. Yes. Under the theory of CAPM, beta is a measure of the systematic risk of a security as compared to the systematic risk of the market as a whole. Beta is a coefficient resulting from a regression of the return of a single stock to the return of the market. The beta for the market is always equal to 1.00. Therefore, companies whose securities have betas greater than 1.00 are considered riskier than the market as a whole, while companies with betas less than 1.00 are considered less risky than the market as a whole. CAPM is based on the concept that risk-averse investors demand higher returns for assuming additional risk and, accordingly, higher risk securities are priced to yield higher returns than lower risk securities. Under CAPM theory, there is an incremental premium for bearing additional risk, as measured by beta, above the base risk-free rate, which is traditionally...
seen as the income return available from investing in U.S. Government Treasury Securities. The specific formula of CAPM is expressed as:

Equation (1): $$K_e = R_f + B(R_p)$$

Where:

- $$K_e$$ = annual required cost of equity
- $$R_f$$ = risk-free rate
- $$B$$ = beta
- $$R_p$$ = risk premium which reflects the market return less the risk-free rate

Q. What risk-free rate of return have you used?
A. For purposes of my analyses, I have used the yield on 30-Year US Treasury Bonds. According to the February 2009 edition of Global Insight’s U.S. Economic Outlook, the average yield on 30-Year US Treasury Bonds for the test year ending September 2010 is estimated to be 3.67%. The estimate for 30-Year US Treasury Bonds from the March 1, 2009 edition of Blue Chip Financial Forecasts is 3.95%. I have used the average of these two 30-year Treasury Bond estimates, 3.81% $$((3.67+3.95)/2)$$, in my CAPM analysis.

Q. Why did you choose to use the 30-year yield?
A. The time horizon of the chosen Treasury security should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond.

Q. Why did you use the year ending September 30, 2010?
A. I used that test year since it is the test year for this proceeding.
Q. Did you use a historic risk premium or a prospective market risk premium?
A. I performed analyses using both historic risk premium and prospective risk premium. However, I believe the CAPM using prospective risk premium is more appropriate in the current market environment. Since the risk free rate I am using in the CAPM model is prospective, it is appropriate to use the prospective risk premium. Traditionally, the prospective risk premium has not varied significantly from the historical risk premium and therefore a historical risk premium was often used as a proxy for the future. However, there has been an unprecedented change in investor attitudes towards risk during the last 12 months. The risk free rate (i.e., Treasury rate) has gone down at the same time when required return on non-Treasury investments has gone up significantly, reflecting a strong risk averse nature of investors. Therefore, I believe it is more appropriate to use prospective market risk premium at this time.

This concept of is discussed in an April 2009 article from JP Morgan entitled Challenges Ahead, Building a New Power Infrastructure in Today’s Financial Paradigm, further support my conclusions:

“Today’s capital markets are marked by historically elevated volatility, significant increases in the pricing of risk and cost of capital, uncertain capital markets access, and the erosion of liquidity across many asset classes.”

“We believe that the historical risk premium method (historic arithmetic average) used by many is too static and that it is unable to accurately capture the current effect of a rapidly changing market environment.”

I agree with these assessments and adopt the conclusions that are set forth in the above quotation.
Q. What is the source of your historic market risk premium?

A. The source for my historic market premium is the 2009 Yearbook for Stocks, Bonds, Bills and Inflation 1926 – 2008. The Yearbook is now published by Morningstar which acquired Ibbotson in 2006. As shown on page 2 of Exhibit A-68 (DVR-10), the average total stock market return for the 1926 – 2008 period was 11.67%. During that same period of time, the average income return of Long-Term Government Bonds was 5.20%. The result is a market premium of 6.47%. The Morningstar/Ibbotson data is often used in developing the market premium.

Q. Why have you used 83 years of data?

A. The 83-year period reflects the entire period used in Morningstar/Ibbotson data.

Q. What does a prospective market risk premium represent?

A. A prospective market risk premium provides an estimate of what risk premium is expected from investments in the current marketplace compared to the risk free rate. The risk premium is the difference between the expected returns on a market index and the risk free rate. This approach is forward looking in contrast to the historical risk premium approach which measures the difference between historical market returns and historical risk free rate. As mentioned earlier, this is a more appropriate approach in the current economic environment.

Q. What was your source for the prospective market risk premium?

A. I used 9%, the mid-point of the market risk premium range of 8-10% identified by JP Morgan in their April 2009 presentation entitled, “Market Risk Premium Overview.” I concluded that this provided an appropriate proxy to use for purposes of the prospective market risk premium analysis.
Q. What beta did you use for purposes of your CAPM analysis?
A. I used the values of beta calculated by Value Line. Value Line computes historical betas using data over the last five years and adjusts this historical beta using the method prescribed by Marshall E. Blume to make it an expected beta. Value Line betas are often used in CAPM analyses. The values of beta for my proxy group of companies are found on page 3 of Exhibit A-68 (DVR-10). The current average beta for my proxy group is 0.67. The beta for CMS Energy is 0.85.

Q. What are the results of applying the CAPM on the group of proxy companies?
A. The historic risk premium results found on page 3 of Exhibit A-68 (DVR-10), column (h), show the average return on equity for my proxy group is 8.12% and ranges from a minimum of 7.69% to a maximum of 8.66%. The medium value is 8.01%.

The prospective risk premium results found on page 3 of Exhibit A-68 (DVR-10), column (i), show the average return on equity for my proxy group is 9.81% and ranges from a minimum of 9.21% to a maximum of 10.56%. The median value is 9.66%.

Q. What were the results of the CAPM analysis you indicated you performed on CMS Energy?
A. The results of the CAPM analysis for CMS Energy are also shown on page 3 of Exhibit A-68 (DVR-10). The results are a required return of 9.31% for CMS Energy for the historic risk premium and 11.46% for the prospective risk premium approach.

Q. What weight would you put on the CAPM results using historical market risk premium?
A. I have given only minimal weight to the results from CAPM using historical risk premium for the reasons mentioned earlier. The average return of the proxy group of 8.12% suggested by this approach is lower than the average 30 year utility bond rates...
shown on Exhibit A-68 (DVR-10), page 7. This represents an anomaly considering the fact that equity is riskier than bonds and should have a higher cost and understates the required return.

3. Risk Premium Analysis

Q. Please describe the risk premium analysis that you performed.

A. I examined the risk premiums of gas utility common stocks over the yield on utility bonds. Page 4 of Exhibit A-68 (DVR-10), column (h), shows that gas utility common stocks have an average risk premium of 3.45% over the yields of A-rated utility bonds. Page 7 of Exhibit A-68 (DVR-10) then calculates the ROE of various bond ratings by adding this risk premium to: 1) the forecasted risk-free rate of 3.81% and 2) the bond spreads over US Treasury bonds found on page 6 of Exhibit A-68 (DVR-10) of 4.42%. The risk premium ROE returns are 11.68% for A/A3 rated utilities (proxy group average ratings) and 12.01% for BBB/Baa1 rated utilities (Consumers Energy’s credit ratings).

Q. Do you believe the risk premium analysis you have performed reflects the current market conditions and investor expectations?

A. Yes, I believe that this cost of capital methodology provides a reasonable assessment of what equity investors would require to make investments in our company in the current market. This methodology provides a better indication of the return that equity investors will demand in the current environment than does the CAPM.

4. Discounted Cash Flow Analysis

Q. Briefly describe the DCF model.

A. The DCF model, which is a type of income model, was developed by John Burr Williams and elaborated by Myron J. Gordon and Eli Shapiro. It was initially employed as a method of valuing the price of common stock by discounting future cash flows by the
cost of capital. In its simplest form, this model can be used to estimate the required cost
of equity capital for a dividend-paying stock with an assumed constant expected growth
rate to perpetuity. This is generally projected as follows:

Equation (2): \[ K_e = \frac{D_1}{P_0} + g \]
where \( D_1 = D_0 (1+g) \)

1. \( K_e \) = the annual required cost of equity capital
2. \( D_0 \) = the current annual dividend
3. \( D_1 \) = the annual dividend received at the end of the first year
4. \( P_0 \) = the current stock price
5. \( g \) = the expected growth rate

This application of the model is displayed on page 8 of Exhibit A-68 (DVR-10).

Q. What is the theoretical basis underlying the DCF model?

A. The DCF model is based upon an analysis of publicly traded common stock. The DCF
theory holds that an investor who agrees to purchase common stock at a given market
price is purchasing the rights to an income stream. That income stream includes the
present and anticipated earnings, the portion of those earnings that are currently and
prospectively being paid to investors in the form of dividends, and the proceeds of capital
appreciation derived from the ultimate sale of the stock at some future market price.

Implicit in the investor’s decision to buy is the assumption that the investor
considers the magnitude of that income stream. This includes the rate at which those
earnings and dividends are expected to grow, and the expected future selling price of the
stock. The investor also considers the quality or risk of that income stream; that is, the likelihood that expectations will, in fact, be realized.

Based upon all these considerations, the investor agrees to pay a given market price for the stock at a given moment in time. Presumably, that market price represents the present value of that anticipated income stream, including dividend and price appreciation, at some discount rate. This can be expressed as follows:

Equation (3): \( P_0 = \frac{D_1}{1+K_e} + \frac{D_2}{(1+K_e)^2} + \ldots + \frac{D_n}{(1+K_e)^n} + \frac{P_n}{(1+K_e)^n} \)

Here, the value of the future anticipated stock price \( (P_n) \) and dividends \( (D_1, D_2, \ldots, D_n) \) are discounted based upon the perceived risk of the investment \( (K_e) \). Note, however, that even the future stock price \( (P_n) \) becomes a function of anticipated dividend appreciation so that, ultimately, the price of the stock today is a function of the present value of growth of the dividend stream to infinity.

The standard annual form of the DCF model presented in Equation (2) above can be referred to as the dividend growth model. It is equal to the expected dividend yield \( (D_1/P_0) \) plus the expected rate of growth in dividends \( (g) \). It assumes an annual dividend payment and that dividends, earnings, book value and price per share grow at the same constant annual rate.

Q. Please explain how you calculated the dividend yield.

A. In theory, the DCF method calls for the “spot dividend yield” that is anticipated by investors at the time the required cost of equity capital is determined. Consequently, in theory the yield would be calculated by dividing the expected annual dividend by the most current stock price. However, spot stock prices are subject to short-term market
fluctuations and an average price is more reliable. I used an average of 30 daily closing stock prices covering the period Feb 11, 2009 – March 25, 2009.

Q. How did you determine the dividend yield for each of the proxy companies?
A. For each of the proxy companies I first determined the average closing stock price for the period identified above. This provided an estimate of P₀. Then I obtained the latest dividend amount from Yahoo Finance. I then divided the annualized dividend by the average stock price (P₀) to determine the current dividend yield. Next, I adjusted the current dividend yield by multiplying it by one plus the growth rate to obtain the expected dividend yield. The expected dividend yield is based on the expected dividend at the end of the first year (D₁) versus the current dividend (D₀). This process was repeated for each of the proxy companies. The stock average prices, dividend amounts and dividend yields are shown on page 8 of Exhibit A-68 (DVR-10).

Q. How did you determine the growth rate for the DCF calculations?
A. For purposes of determining the growth rate I used an average of the earnings growth rates from Zacks, Institutional Brokers’ Estimate System (“IBES”) and Value Line. These forecasts are available to investors and provide a proxy for investor expectations. The Zacks, IBES and Value Line estimates are shown on page 8 of Exhibit A-68 (DVR-10). These forecasts are commonly used in DCF calculations.

Q. What were the results of your DCF cost of equity analyses for the proxy companies?
A. Page 8 of Exhibit A-68 (DVR-10) shows the results for my group of proxy companies. Proxy group company returns range from 9.78% to 12.23% and have an average return of 10.63%. The median return is 10.47%.
Q. What was the result of your DCF analysis for CMS Energy?
A. The DCF result for CMS Energy is 12.61%.

5. Value Line Book Value Method

Q. Briefly describe the Value Line Book Value method.
A. This method calculates a projected earned ROE for the proxy group based on Value Line projections of earnings and book value per share. This information is readily available to investors. Projected earnings per share are divided by the projected book value per share to calculate a projected return on equity. The results from this method factor in current market expectations for these companies. Page 9 of Exhibit A-68 (DVR-10) shows the results for my group of proxy companies. The average result for the proxy group is 11.74% and the median is 11.31%.

D. FINANCIAL RISK ANALYSIS

1. Proxy Group Risk Comparison

Q. How does the proxy company group compare to Consumers Energy?
A. Based on my analysis of credit ratings, financial ratios and actual earned return on equity, I conclude that the Consumers Energy’s gas business has higher risk than the proxy group of companies in Exhibit A-68 (DVR-10). The credit ratings assigned by Standard and Poor’s and Moody’s for senior secured debt indicate that investors view the senior secured bonds of Consumers Energy as having greater risk than the bonds issued by the proxy group on average. In addition, the funds from operations coverage ratios shown for Consumers Energy are weaker than the average ratios for the proxy group. Also, Consumers Energy’s gas business has not earned its authorized return on common equity
for a number of years. Investors take this into account whether a utility earns at or near its authorized return in evaluating risk. The returns earned by the proxy companies for 2008 on average were 11.09%.

Q. What are the senior secured bond credit ratings assigned by Standard and Poor’s and Moody’s for Consumers Energy and for the proxy group on average?

A. As shown in page 4 of my Exhibit A-67 (DVR-9), the senior secured bonds of Consumers Energy are rated “BBB” by S&P and “Baa1” by Moody’s. As shown on page 4 of Exhibit A-67 (DVR-9), the average Moody’s and S&P’s bond ratings for the proxy group are A3 and A, respectively.

Q. What is the senior secured debt credit rating differential between the proxy group and for Consumers Energy?

A. Moody’s and S&P’s classify investment grade bonds using the following rating categories:

<table>
<thead>
<tr>
<th>Moody’s</th>
<th>S&amp;P</th>
</tr>
</thead>
<tbody>
<tr>
<td>(highest)</td>
<td>Aaa</td>
</tr>
<tr>
<td></td>
<td>Aa1</td>
</tr>
<tr>
<td></td>
<td>Aa2</td>
</tr>
<tr>
<td></td>
<td>Aa3</td>
</tr>
<tr>
<td></td>
<td>A1</td>
</tr>
<tr>
<td></td>
<td>A2</td>
</tr>
<tr>
<td></td>
<td>A3</td>
</tr>
<tr>
<td></td>
<td>Baa1</td>
</tr>
<tr>
<td></td>
<td>Baa2</td>
</tr>
<tr>
<td>(lowest)</td>
<td>Baa3</td>
</tr>
</tbody>
</table>

The majority of the companies in the proxy group are rated “A” or higher by S&P and “A3” or higher by Moody’s. The average S&P rating for the proxy group was “A” and the average Moody’s rating was “A3”. This represents a rating differential of one to
three notches between Consumers Energy and the proxy group with Consumers Energy being perceived as having a greater financial risk than the proxy group.

Q. What is the significance of credit rating differential between the proxy group and Consumers Energy?

A. The credit rating differential represents a difference in risk perceptions of the investors. As the credit rating becomes lower (i.e., more risky), the investors expect a higher return to compensate them for the increased risk. Page 2 of my Exhibit A-67 (DVR-9) shows the spread differentials above the U.S. treasury rate for different bond ratings. Page 2 shows that the average spread differential between the “A” rated bonds and “BBB” rated bonds from January 1, 2007 through March 2009 was 48 basis points (bps). This indicates that the return required by investors from a “BBB” rated bond was 48 bps higher than the return required by investors from an “A” rated bond.

Investment in equity is considered by investors to be more risky than investment in bonds. Since equity is considered riskier than the bonds, this would indicate that the cost of equity differential between the return required by investors for equity investments during this time period in a “BBB” rated company would be at least 48 bps higher than the return required for an “A” rated company.

Q. Please explain the importance of coverage ratios.

A. Two of the quantitative measures used by credit rating agencies to examine the debt servicing ability of any company are the ratio of Funds From Operations (FFO) to interest expense and the ratio of FFO to Average Debt. The higher these ratios are, the higher is the certainty of servicing the debt principal and interest payments satisfactorily. These ratios as calculated by Moody’s for the period 2005-07 are shown in columns (e) and (f)
on page 4 of Exhibit A-67 (DVR-9). As can be noticed, the FFO ratios of Consumers Energy were lower than average ratios of proxy group companies. This represents higher financial risk for Consumers Energy than the companies in the proxy group.

Q. Please explain why the Consumers’ FFO based coverage ratios continue to be low?

A. While equity infusions help improve debt to capital ratio of the Company, the other financial indicators such as FFO ratios improve only after the cash flow improves. Improvement in cash flow occurs after the Company is able to earn the authorized return. Therefore, it is important for the Commission to not only provide the rate relief with a reasonable return but to allow the Company a reasonable opportunity to earn the authorized return. Exhibit A-67 (DVR-9), page 5, indicates that during 2008, Consumers Energy’s gas financial return on equity was below its authorized return.

Q. What are investors’ expectations regarding return on equity?

A. Investors expect the Company to earn the authorized rate of return on a financial basis. They also look at the ratemaking return on equity in view of the regulatory considerations.

Q. How did Consumers Energy’s gas business perform as measured by the earned financial return on equity?

A. Page 5 of Exhibit A-67 (DVR-9) identifies the financial return on equity earned by the gas business unit from December 2007 to December 2008. The financial return on equity numbers are submitted by the Company every month to the Commission and are posted on the MPSC website. Each bar represents the financial return on equity earned by the Consumers Energy’s gas business during the prior 12 month period, on a rolling basis.
As can be seen, the Consumers Energy’s gas business earned a return of 9.22% during the year ended December 2008.

Q. How does this compare to the financial performance of proxy group companies?

A. As shown on the right hand side table on page 5 of Exhibit A-67 (DVR-9), the proxy group, on average, earned a return on equity of 11.09% during 2008 as reported by Value Line, compared to the 9.22% return earned by Consumers Energy’s gas business.

Q. Why is historical performance relevant to setting the return on equity?

A. The historical record affects investor perceptions of the risk that a company will earn a return which compensates the investor for assumed risk. The lower the variability in historical return as compared to the authorized return, the better it is for investors in assessing risk assumed. All else being equal, low returns compared to perceived risk and fluctuations in returns both tend to increase the risk resulting in investors requiring a higher return.

Q. Have you concluded how Consumers Energy’s gas business financial risk compares with the proxy group?

A. Yes. I have concluded that Consumers Energy’s gas business has higher financial risk than my proxy group of companies. In addition, Michigan’s lagging economy, which has had the highest state unemployment rate according to the Bureau of Labor Statistics of the United Stated Department of Labor\(^1\) and has ranked last among the states since 2003 in cumulative real GDP growth\(^2\). These factors result in addition investor-perceived additional business risk relative to the proxy group.

---

\(^1\) Bureau of Labor Statistics, United States Department of Labor, April 17, 2009, USDL 09-0391

\(^2\) Michigan Brief, Comerica Bank, July 25, 2008, 2008: No. 3
Q. What impact does the overall lower risk of the proxy group have on the rate of return results?

A. The impact is that the less risky companies produce return on equity results that on average would be lower than a return on equity appropriate for Consumers Energy’s gas business.

Q. How did you estimate the additional return required for Consumers Energy due to its additional risk?

A. To estimate the additional return required by Consumers Energy relative to the proxy group, I computed the long-term bond spread difference between the proxy group’s average credit ratings and the credit ratings of Consumers Energy. Since equity is more risky than debt, this would be the minimum spread that should be added to the ROE results for the proxy companies to reflect the added risk of Consumers Energy.

Q. What is the long-term bond spread difference between the average proxy group credit rating and the credit rating of Consumers Energy?

A. The current 30 year bond spread difference between the A/A3 average proxy group rating and the BBB/Baa1 rating of Consumers Energy is approximately 34 basis points or 0.34%. The calculation of this spread difference is shown on page 6 of Exhibit A-68 (DVR-10).
2. **Risk Comparison to prior Case No. U-15506**

Q. Please describe how investors’ perception of risk has changed since Consumers’ last gas rate case U-15506.

A. The recent turmoil in the financial markets has severely impacted the risk perceptions of both debt and equity investors. Investors have become more risk averse and are demanding higher returns on similar investments. Consumers Energy, like most companies in the market, is experiencing higher cost of debt and equity. The increased perceptions of risk by investors is illustrated by comparing the bond yields of Consumers and other similar rated bonds as well as the Price to Earnings (P/E) ratios of the companies in the proxy group shown on page 3 of Exhibit A-67 (DVR-9).

Q. Please explain further.

A. The chart on Page 1 of Exhibit A-67 (DVR-9) shows the trend in Consumers bond yield and 10 year U.S. treasury rate since January 2007. As can be noticed, the spread on Consumers bonds has widened significantly since January 2007 and the overall yield has increased despite the drop in U.S. treasury rates. Page 2 of Exhibit A-67 (DVR-9) shows similar increase in spreads experienced on other BBB rated industrial bonds.

The following table provides a summary of Consumers’ bond yields and spreads for the month of January over the past few years:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Treasury Yield</td>
<td>4.8%</td>
<td>3.7%</td>
<td>2.5%</td>
</tr>
<tr>
<td>Consumers Spread over Treasuries</td>
<td>1.0%</td>
<td>1.7%</td>
<td>3.7%</td>
</tr>
<tr>
<td>Consumers Bond Yield %</td>
<td>5.7%</td>
<td>5.4%</td>
<td>6.2%</td>
</tr>
</tbody>
</table>

January 2008 to January 2009 % Change

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.8%</td>
</tr>
</tbody>
</table>

It can be observed from the above table that Consumers bond yield has risen considerably from early 2008 levels. Consumers’ bond yield in January 2009 was approximately 80
basis points higher than the same month in 2008. Even though treasury yields dropped 1.2% over the period bond spreads increased 2.0%, thus driving the overall cost up 0.8%. This further supports my assessment discussed throughout this testimony that the risk aversion of investors is driving up capital costs for market participants. Since equity is riskier than bonds, it is reasonable to conclude that the cost of Consumers equity has increased by at least this amount, if not higher. Given current economic conditions, I do not expect Consumers’ yield in the test year to be lower than the yield experienced in early 2009, which represents an increase since Consumers’ last rate case. This supports a conclusion that the currently required return is higher than at the time of the last case.

Q. Please explain your analysis of the Price to Earnings ratio of proxy group companies which is shown on Exhibit A-67 (DVR-9), page 3.

A. Exhibit A-67 (DVR-9) shows that there has been a decline in Price to Earnings (P/E) ratio for the proxy group as a whole, as well as for the individual companies in proxy group. The P/E ratio is defined as a ratio of the market price of the stock (P) to the Earnings Per Share (E) and is one of the tools to used by analysts to measure the cost of equity of any particular company. Lower P/E ratio means that the investors are paying a lower price for a given company’s stock for the same level of earnings. In other words, the earnings are being considered more risky than before and being discounted at a higher rate than before.

Page 3 of Exhibit A-67 (DVR-9) shows the historical P/E ratios of the proxy group companies and the ratios experienced in March 2009, as published by Value Line. It can be observed that the average historical P/E ratio for the proxy group was 15.7. In March 2009, 100% of the proxy group has experienced a decline in P/E ratio lowering the
average ratio by approximately 21% from historical levels. This supports the conclusion that the cost of equity for utilities in general has been increasing. Investors, as a whole, are requiring higher returns on the capital investments than they did before the current economic crisis.

Q. What ROE are you recommending be used in this case?

A. In determining a ROE recommendation, I reviewed the average and median results from the CAPM, Risk Premium, DCF analyses, and Value Line Book Value ROE methods described above. I then adjusted those results to reflect the additional risk of Consumers Energy as measured by differences in credit ratings of Consumers Energy as compared to the average credit ratings of the proxy group. These results are summarized on page 10 of Exhibit A-68 (DVR–10). The average and median results for the proxy companies are listed in the first five lines of page 10 of Exhibit A-68 (DVR-10). These results are adjusted for the additional risk of Consumers Energy on lines 7 – 11. The adjustment for the corporate bond spread differential that is used in the adjustment is shown on line 6. This adjustment is conservative. Based on the results and on my professional judgment, I am recommending a range for Consumers Energy’s gas business in this case of 10.75% to 11.25% and that a return on equity for Consumers Energy’s gas business be set at not less than 11.00%.

E. ROE SUMMARY AND CONCLUSIONS

Q. Please provide your summary and conclusion.

A. Based on the analyses and adjustments described above and summarized in on page 10 of Exhibit A-68 (DVR-10), I conclude that the authorized rate should reflect an opportunity for Consumers Energy’s gas operations to earn a return on its common equity of not less
than 11.00%. If the decoupling and uncollectable tracker mechanisms requested in this case are not adopted, I would recommend that the ROE be higher than 11.00% to reflect the added risk.

**IV. ACCOUNTS RECEIVABLE FINANCING**

**A. Accounts Receivable Financing Program Utilization**

Q. What is the maximum capacity of Accounts Receivable (A/R) financing facility available to the Company?

A. The maximum capacity of the A/R financing facility is currently $250 million. Until November 4, 2008, the maximum size of facility was $325 million. However, pursuant to an amendment signed on November 5, 2008 between the Company and the financing parties, the size of facility was reduced to $250 million along with an increase in the permissible level of uncollectible (or bad debt) expense. This amendment was driven by the current economic environment.

Q. What is your recommendation regarding the level of utilization of Accounts Receivables (A/R) financing for the test year ending September 30, 2010?

A. I am recommending the level of utilization of A/R financing to be used for the purposes of setting rates for the test year ending September 30, 2010 to be $146.2 million, as shown in Exhibit A-66 (DVR-8). I have arrived at these monthly projections after considering the projected monthly cash flow requirement, planned long term debt issuances/retirements and equity issuances.

Q. Please explain your methodology further.

A. I have first projected the monthly sources of cash including net income and depreciation/amortization for the total company. Then, I have considered the seasonality of working
capital requirements, and quarterly payments of dividends and taxes. I have also considered pension cash contribution and monthly capital expenditures. This provided me the monthly cash shortfall or surplus, before financing. I have then layered on the planned long term debt issuance, long term debt retirements and equity infusion as discussed earlier in my testimony. This provided me the total amount of short term financing to be obtained from short term facilities (i.e. A/R financing facility and Revolver). I have assumed that the Company will use short term facilities when there is a cash shortfall and does not use the facilities when there is adequate cash. I have also assumed that the A/R facility will be drawn first, up to the maximum capacity of $250 million (as it is expected to be cheaper than the Revolver) and then the Revolver will be drawn as needed. The projected balances of A/R financing and short term debt for the test year determined with this approach are shown in Exhibit A-66 (DVR-8). The profile of monthly balances is consistent with the historical trend where the Company borrowed on short term facilities during fall and winter months and no short term funding was required during summer months. Under this approach, the Company uses the short term facilities in an efficient manner consistent with the Commission’s guidelines in Case U-15245.

Q. Would it be appropriate to determine the short term financing requirement by just using gas inventory alone?

A. No. Determining the short term financing requirement by using gas inventory alone is not appropriate since it is not a complete analysis. It does not consider the monthly cash impacts of the items I mentioned above including timing of receivables or cash collections from customers, payables, quarterly payment of dividends and taxes, timing
of depreciation versus capital expenditures and the timing of long term debt and equity issuances. Also, as mentioned earlier, the Company plans to issue long term debt a few months in advance of the maturity due in August 2009 given the uncertainty in credit markets. The cash from this issuance will be available for short term use until the maturity is paid off in August 2009. Similarly, the cash from the September 2008 debt issue will be available for short term use during the winter months of 2008-09 until the February 2009 maturity is paid off. All these factors contribute to the determination of short term financing needs and not the gas inventory alone.

Q. Would it be appropriate to assume that accounts receivable financing should be used 100% of the time at the maximum amount?

A. No, I do not agree that accounts receivable financing should be used 100% of the time at the maximum amount for the following reasons:

- It is against the prudent and established financial practice of “maturity matching”. Maturity “mismatch” is one of main reasons for the failure of several banks that led to the current crisis in the financial markets,
- It exposes the Company and its customers to higher risks,
- It reduces liquidity available to the Company, the importance of which can not be overemphasized especially in a volatile and turbulent credit market, and
- It would be inefficient to draw against the accounts receivable financing facility during months when there are no short-term financing needs.

I will elaborate on each of the points in my testimony below.
Q. In its order in Case No. U-15245 the Commission indicated that sale of accounts receivable to third parties at a discount should be used if it is the lowest cost means to cover short-term financial needs. Is your recommendation consistent with this goal?

A. Yes. In developing my recommendation I have taken into consideration a number of factors including the principles set forth in the Commission’s order in Case No. U-15245, the actual utilization of A/R financing by the Company in the last 3 years, the projected cash flow requirement, the size of the facility and fundamental principles of financial management.

Q. Please describe the principles related to A/R financing approach discussed in the Commission’s order in Case No. U-15245.

A. On page 11 of the order in Case No. U-15245, the Commission stated that using accounts receivable financing to meet short-term capital needs “is the approach that the Commission generally supports in determining working capital requirements and in setting just and reasonable rates.” Consequently, an initial question that needs to be addressed is the pattern and amount of the Company’s short-term capital needs during a year.

Q. Does the Company have the same level of “short term” capital needs every month?

A. No. By definition, if a certain amount of short term capital is required consistently in every month, it is no longer a “short term” capital need. It is more of a “permanent” capital need. The Company’s short-term capital needs vary during the year. This is shown on Exhibit A-67 DVR-9) which shows actual and projected Accounts Receivable Financing and short-term debt utilization for January 2005 through September 2010. The exhibit illustrates that the Company’s short-term capital needs tend to be highest near the
end of a calendar year and significantly lower, or not present, during the middle of the
year. Also, in determining how a particular need should be funded it is necessary to
consider the financial principle of “maturity matching.”

Q. What is meant by “maturity matching”?

A. Maturity matching is one of the fundamental principles of financial management.
According to the “maturity matching” principle, long term assets should be financed by
long term capital and short term assets should be financed by short term capital. The
phrase “long term assets” here denotes the fixed assets and non-seasonal portion of the
working capital (i.e. the portion of the working capital that does not vary month to
month). The phrase “short term assets” refers to the portion of the working capital that
fluctuates from season to season or from month to month. Funding short-term assets with
short term funding allows the borrowers to pay off the short term capital using the short
term cash flows and then re-borrow when necessary. On the other hand, if the short term
capital is tied up in the long term assets, it exposes the borrower to the risk of renewal
and/or change in interest rates which could have been avoided. This principle of
“maturity matching” is recognized in various financial literature.

Q. Are there practical considerations in implementing “maturity matching” for a Company
such as Consumers?

A. Yes. There are several considerations that will make implementation of a “perfect”
maturity matching difficult, particularly in the current economic environment. For
example, it might not be possible to issue long term debt exactly when it is needed.
Issuing the long term debt slightly in advance would make long term capital available for
short term assets until it is deployed in long term assets. For these reasons, the actual
short term debt requirement would be lower than the theoretical amount suggested by maturity matching concept. Though this situation of having more long term debt than needed can also be called a “mismatch”, it is a practical matter which moves a company towards the conservative side, and not a risky mismatch that is caused by having more “short term debt” than necessary. In fact, it can be appropriate for companies to be more conservative during the times of uncertain credit markets in order to protect liquidity.

Q. Please explain the short term nature of A/R financing facility.

A. A/R financing is a short term financing option. Reasons that it is considered a short-term financing option include that (i) the facility expires every 12 months and needs to be renegotiated, (ii) the financing rate on this is reset monthly based on the actual borrowing cost of the special purpose entity that purchases receivables from Consumers i.e. Falcon Asset Securitization Company LLC (“FASC”), and (iii) the borrowing is tied to receivables, which fluctuate with the season of the year. FASC is an affiliate of JP Morgan Chase Bank. The borrowing cost of FASC, and hence the Company’s cost under this facility, typically tracks the Commercial Paper rate but can be volatile during a tight credit situation.

Q. Does Consumers Energy utilize the A/R financing in the most cost effective manner?

A. Yes. During the months when cash flow is needed most, the Company fully utilizes the A/R financing method. During months when cash flow is not needed it does not use it as much or not at all. As can be seen, in Exhibit A-66 (DVR-8) the usage of the A/R financing and the short-term debt revolver were coordinated so that the lowest cost funds available were used for short-term financing requirements. As shown in Exhibit A-66 (DVR-8) the A/R financing is not typically used in summer months because short-term
financing is not needed, not because more expensive short-term financing is used. It also
shows that during 2005, 2006, 2007, and 2008 the Company did not need to draw upon
either short-term debt or accounts receivable financing during the months of April, May,
June, or July. The projected balances for the test year are consistent with the historical
trends.

Q. What would happen if the Company used the A/R financing in months when cash was
not needed?

A. Using the A/R financing facility when there is adequate cash at the Company is not an
efficient use of the program. Under this scenario, there will be a negative arbitrage since
Company would be raising cash using the A/R facility when there is adequate cash and
reinvesting the cash at a rate lower than cost of A/R facility. The A/R program is a
working capital facility designed to provide a short-term source of funds during the
months when cash is required and Consumers utilized it in an efficient manner in the past
and my projections for 2009 assume an efficient utilization.

Q. Would it be appropriate to assume that the A/R financing would be used at the maximum
available financing level in every month of the year?

A. No. The A/R financing is only an efficient means of financing if it is actually needed for
short-term cash requirements. Using A/R financing when it is not needed because there
is adequate cash at the Company, or using it for long term requirements would not be
efficient and would increase the Company’s risk profile as well as the overall costs that
customers would pay.
Q. Please explain the impact the account receivable sales program has on working capital?

A. Consumers reduces its 13-month average working capital by the average amount of receivables actually sold to outside parties. While projecting the working capital requirement for the test year ending September 30, 2010, the Company assumed the sale of receivables to be at $146.2 million and accordingly reduced the working capital by the same amount, consistent with my approach. Working capital is addressed further by Consumers Energy’s witness Mr. Alfred.

B. Accounts Receivable Financing Program Costs

Q. Please explain the terms of Company’s existing A/R financing agreement.

A. As mentioned earlier, the Company’s A/R financing program expires every year and needs to be renewed. The previous A/R program expired in February 2009 and the Company signed an amendment to renew the program for a 3 month period until May 2009. On April 29th, 2009 the Company signed an amendment to renew the program until February 2010.

Q. How is the cost of the Accounts Receivable Financing Program calculated?

A. I used the Fee letter signed by the Company in February 2009 as the basis for calculating the cost of A/R program. The total cost of A/R program consists of three components – a Base Rate (i.e. Commercial Paper rate), Credit Spread of 0.875% (also referred to as Program Fee) and a Facility Fee of 0.875%. The Base Rate and the Credit Spread are charged on the portion of the accounts receivable balances that are drawn down. However, the Facility Fee is charged on 102% of the maximum amount that is available under the facility. This is a cost of having the facility available to Consumers.
Q. What fee have you projected for the test year ending September 30, 2010?

A. I used an average of the projected the Commercial Paper rate for the 4th quarter of 2009 and 1st three quarters of 2010 from Global Insight’s forecast (Feb 2009 Edition). This average rate is 0.93%. Adding 87.5 basis points to this base rate results in a rate charged on drawn balances of 1.805%. Applying this rate to the average drawn balance of $146.2 million results in a fee of $2,638,910. In addition, the 87.5 basis point facility fee is charged on 102% of the maximum facility or $255 million (102% of $250 million). The facility fee for the test year is $2,231,250 ($255 million * 0.875%). Therefore, the total projected A/R financing cost for the test year is $4,870,160.

V. EXHIBITS FOR CERTAIN NEW FILING REQUIREMENTS

Q. Please describe Exhibit A-69 (DVR-11)?

A. Exhibit A-69 (DVR-11) is included per the new rate case filing requirements. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides current and historical credit ratings, with associated outlooks for the previous five years for the utility and its parent Company. Exhibit A-69 (DVR-11) shows Consumers Energy and CMS Energy current and historical credit ratings, along with associated credit outlooks, for the previous five years as published by Standard and Poor’s (S&P), Moody’s Investors Service (Moody’s) and Fitch Ratings. The credit ratings include senior unsecured debt, senior secured debt, and hybrid securities ratings.

Q. Please describe Exhibit A-70 (DVR-12)?

A. In its December 23, 2008 Order in Case No. U-15895, the Commission directed that utilities include an exhibit that provides certain information related to bond issuances.
VI. SUMMARY AND CONCLUSIONS

Q. Please summarize your recommendations and conclusions.

A. Consumers Energy’s capital structure should be based on the capital structure as of December 31, 2008 adjusted for the expected changes in long term debt and common equity as shown on Exhibit A-59 (DVR-1). I am recommending a Return on Equity of not less than 11.00%, assuming that the uncollectable tracker and decoupling mechanism being requested by the Company in this case are approved by the Commission. If the Commission does not approve the decoupling mechanism and uncollectable trackers requested by the Company, the Return on Equity should be higher than 11% to reflect added risk. The costs rates developed are fair and reasonable and commensurate with the risks for the period of time rates are expected to be in effect. As shown on Exhibit A-59 (DVR-1), I recommend an overall rate of return of 7.28%.

I also recommend that the average Accounts Receivable Financing Program utilization for the test year ending September 30, 2010 be set at $146.2 million. I also recommend a credit spread over commercial paper rates of 87.5 bps and facility fee of 87.5 bps be used in calculating the cost of Accounts Receivable Financing. Based on
$146.2 million of average borrowing, I project the A/R financing cost for the test year to
be $4,870,160.

Q. Does this conclude your direct testimony?
A. Yes.
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
distribution of natural gas and for other relief

Case No. U-15986

DIRECT TESTIMONY

OF

RONN J. RASMUSSEN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business address.

A. My name is Ronn J. Rasmussen and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or "the Company") as Vice President Rates and Regulation.

Q. Please review your educational and business experience.

A. I was graduated from Ferris State College in May of 1978 with a Bachelor of Science Degree in Accounting. I joined the Company in June 1978 and between June 1978 and now I have held various positions in our Accounting, Gas Supply, Business Support, and Rates Departments.

Q. What are your responsibilities as Vice President Rates and Regulation?

A. In my current position, I am responsible for coordinating the activities of the Company’s Rates and Business Support Department, which include revenue requirement, cost allocation, rate design, tariff issues, and a variety of other regulatory activities. I am also responsible for the coordination of the Company’s planning, budgeting, and forecasting functions.

Q. Have you previously testified before this Commission?

A. Yes, on a number of occasions. Most recently I have testified in Case Nos. U-15245 our electric rate case and U-15506 the previous gas rate case filed by the Company.
Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview of the Company’s filing in this proceeding and to summarize the primary factors that give rise to the need for the rate relief requested.

Q. Please describe the overall business environment in which Consumers Energy currently operates.

A. In the Company’s most recent gas rate case, I described a business environment facing most gas distribution companies that included rising natural gas commodity costs and declining deliveries to end use customers. I also noted that even though deliveries were declining, utilities continued to make needed investments to enhance and maintain aging infrastructure. The investments necessary to enhance and maintain our aging infrastructure continue at Consumers Energy. These investments include those required to maintain compliance with pipeline integrity requirements, transmission and storage system upgrades, and distribution system improvements. In general, these investments are made to ensure that the Company is able to safely and reliably deliver natural gas to our customers.

Year-over-year reductions in customers usage also continues. Whether driven directly by customer conservation efforts, improved efficiency, commodity prices or by the impact of the economic downturn, the industry and the Company have seen, and continue to see, substantial reductions in deliveries to customers. That reduction will be compounded as the Company expands its efforts to incent customers to reduce gas usage through energy efficiency improvement programs being implemented this year. In addition, the worldwide, national, and regional economy issues exacerbate the general
downward trend in customers demand for natural gas. According to the Summer 2009 Energy Appraisal produced by the Michigan Public Service Commission, total gas sales for 2009 are projected to fall despite the colder than normal weather because “...the lower level of economic activity has served as an offset holding demand essentially flat.”

Q. Please describe the approach used by the Company in the preparation of this case.

A. This is the Company’s first gas rate case submitted under the provisions of 2008 Public Act 286 (“Act”) and pursuant to the Commission’s newly established filing requirements. The Company has complied with the requirements of both. The historical period selected is the most recent calendar year 2008. Company witness Daniel Alfred has calculated a $47 million revenue deficiency based on historical 2008 booked results.

Q. Is the $47 million revenue deficiency based on historical booked results adequate for final relief?

A. No. Among other things, the Company has made and will continue to make a significant investment in gas rate base to enhance system reliability, deliverability and customer...
service. A projected test period is necessary to reflect the new investment and related costs the Company expects to experience in the near term. The Company has selected a future test period of the 12 months ended September 30, 2010. During the future test period, Consumers Energy’s investment in average gas rate base is expected to grow to over $2.9 billion, an increase of over $377 million from the 2008 level included in current rates.

I should note that while a significant portion of the filing is based on historical information, there are certain items that the Company has projected utilizing more recent developments and trends. These items include deliveries, uncollectible accounts expenses, and pension and benefit expenses. Given the volatility and unpredictability of these expenses, the Company proposes that the Commission approve rate adjustment mechanisms that allow for the reconciliation of actual expenses to those included in rates. Such reconciliations are the Company’s preferred approach to assuring that customers and the Company are fairly treated regarding the impact of those significant items on rates and charges. These adjustment mechanisms are detailed in the testimony of Company witnesses Daniel Harry, Rachel Pender, and Herbert Kops.

Q. Please summarize the factual basis for the adoption of a rate adjustment mechanism for uncollectible accounts expense.

A. As shown below, the Company is experiencing dramatic increases in uncollectible accounts expense which is being fueled by the state of the Michigan economy and the significant increase in unemployment.
The Company is proposing an uncollectible true-up mechanism (UTM) to protect Consumers and its customers from the potential future volatility in uncollectible expense.

Q. Please summarize the factual basis for the rate adjustments mechanism for deliveries.

A. As specifically allowed under Section 89(6) of the PA 295, Consumers Energy is proposing a symmetrical revenue true-up mechanism that adjusts for sales volumes that are above or below the projected levels that were used to determine the revenue requirements as approved by the Commission in this case. The mechanism is a critical element to aligning the interest of customers and the utility’s investors, by removing the inherent disincentive that exists for the utility to reduce its sales.
Q. Please summarize the basis for the rate adjustment mechanism for pension and benefits expenses.

A. The sensitivity of pension and retiree health care expenses to changes in both interest rates and asset returns creates a significant potential for large variability in future pension and retiree health care costs. Since pension and retiree health care expenses are both recognized in the ratemaking process, both customers and the Company would benefit from the establishment of an adjustment mechanism that eliminates the risk of inaccurately establishing the level of these expenses to be included in rates. The Pension Equalization Mechanism (PEM) and the OPEB Equalization Mechanism (OEM) would allow the Company to annually defer the difference between the expenses included in rates and the actual expenses recorded by the Company.

Q. Is there any regulatory precedent for these mechanisms?

A. Yes. The Company was authorized by the Commission to implement PEM and OEM in its November 21, 2006 order in Case No. U-14547. Those mechanisms remained in place until August 21, 2007.

Q. Please discuss the return on equity level requested by the Company.

A. Witness Rao addresses in great detail the Company’s proposal regarding return on equity. I emphasize here that an appropriate return level is a critical component in this ratemaking process that allows the Company to attract capital at reasonable rates, to invest in the critical infrastructure described in this filing, and to support our ongoing investment in Michigan and the jobs that come with that investment.
Q. Please identify and quantify the primary drivers of the relief requested in this proceeding.

A. As I have noted above, the necessary investment in infrastructure and the decline in deliveries are substantial drivers. Changes in uncollectible expenses and pension and benefit expenses are also contributing factors. Changes in capital structure and financing costs also drive the increase. The following table quantifies the impacts of these items.

<table>
<thead>
<tr>
<th>Key Drivers</th>
<th>$Millions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Base</td>
<td>$46</td>
</tr>
<tr>
<td>Gross Margin (Deliveries)</td>
<td>$40</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>$25</td>
</tr>
<tr>
<td>- Uncollectible Accounts</td>
<td>$17</td>
</tr>
<tr>
<td>- Pension and Health Care</td>
<td>$7</td>
</tr>
<tr>
<td>- Inflation and Other</td>
<td>$1</td>
</tr>
<tr>
<td>Cost of Capital</td>
<td>$8</td>
</tr>
<tr>
<td>Taxes and Other</td>
<td>$(5)</td>
</tr>
<tr>
<td>Revenue Deficiency</td>
<td>$114</td>
</tr>
</tbody>
</table>

Q. Do you have any other items to address?

A. Yes. Although the relief requested in this proceeding does impact customer rates, I would note that Consumers Energy continues to deliver natural gas to our customers at a price among the lowest in the country. As reflected below, recent national price comparisons show that Consumers residential rates are well below the national average.
Q. Do you have any other observations on customer rates or customer impacts?

A. Yes. While the Company is requesting an increase in the gas delivery rates, recent reductions in the price of the natural gas commodity are likely to result in lower gas billings for our residential customers than they received a year ago as shown in the chart below, even with the requested distribution rate increase.

Although our customer rates remain extremely competitive the Company understands that many customers are having difficulty making ends meet in these difficult economic
times. The Company proposes in this case to continue to fund the Low Income Energy Efficiency Fund at the present level of $17 million annually. In addition, the Company has proposed herein to establish an Income Assistance Service Provision for customers whose total household income does not exceed 150% of the Federal Poverty Level. This discount, described in witness Rachel Pender’s testimony and exhibits, will further assist qualifying customers in lowering their charges for natural gas service by eliminating the monthly customer charge. These efforts are in addition to many other financial assistance programs in which Consumers Energy participates, including programs like Michigan Home Heating Credit, State Emergency Relief, Winter Protection Plan, Shut off Protection Plan, People Care and Gatekeeper.

Q. Has the Company made any adjustments to its historical employee compensation levels in this filing?

A. All payments made to officers pursuant to the Employee Incentive Compensation Plan have been removed from the revenue requirement calculated in this filing. With respect to non-officer compensation, Consumers Energy uses market survey data to determine an overall competitive level of compensation. The overall compensation levels, including non-officer EICP compensation, are set at levels that this survey indicates are reasonable and competitive with the market. If the EICP payments were excluded from consideration, overall non-officer compensation would be below the competitive levels necessary to attract and maintain a qualified workforce. Thus, no adjustments to non-officer compensation are reflected in the Company’s revenue requirements calculations, and none are appropriate.
Q. Does this conclude your testimony in this proceeding?

A. Yes, it does.
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
distribution of natural gas and for other relief

Case No. U-15986

DIRECT TESTIMONY

OF

THEODORE J. VOGEL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business address.
A. Theodore J. Vogel. My business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?
A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”) as Vice President and Chief Tax Counsel. I am also Vice President and Chief Tax Counsel of CMS Energy Corporation, parent company of Consumers Energy.

Q. Please briefly describe your professional background and work experience.
A. I joined Consumers Energy as an attorney in the Legal Department in 1979, responsible for various finance, tax and general corporate law matters. I was named Director of Corporate Taxes and Tax Counsel in 1987 and Vice President and Tax Counsel in 1997, and have been responsible for the tax matters of the CMS Energy consolidated group of companies since 1987, with the exception of 2000-2001 when I served as Vice President and Tax Counsel for DTE Energy Company. I was an accountant in Vannatter, Howell and Company, CPAs, Grand Rapids, Michigan during the years 1974-1976. I am a graduate of Calvin College (BA, 1974), The University of Michigan Law School (JD, 1979) and The University of Michigan School of Business Administration (MBA with high distinction, 1992). I am a member of the American Bar Association, where I served as Chair of the Taxation and Accounting Committee of the Section of Public Utility, Communications and Transportation Law, and am also a member of the Taxation Section. I am a member of the Tax Executives Institute, where I currently serve on the international Board of Directors and previously served as President of the Detroit Chapter. I am a member and former Chair of the Taxation Committee of the Edison Electric Institute, and continue to serve on its leadership committee. I am also a
member and former Chair of the Michigan Chamber of Commerce Taxation Committee and a member of the Tax Committee of the Michigan Manufacturers Association. I am admitted to practice law in the State of Michigan and certain federal courts, including the U.S. Tax Court and the U.S. Supreme Court.

Q. What are your responsibilities as Vice President and Chief Tax Counsel?
A. I have overall responsibility for the tax matters CMS Energy and its subsidiaries, including Consumers Energy. This role includes advising management with respect to tax law matters, and overseeing tax compliance, tax-related strategic planning, transaction analysis, and tax audits and litigation. I am also responsible, together with the Vice President and Chief Accounting Officer, for tax-related financial accounting and disclosure matters. I am also responsible for analyzing the impact of proposed and/or enacted tax legislation on Consumers Energy and, at times, for providing input to various governmental authorities.

Q. Have you previously testified before the Michigan Public Service Commission?
A. Yes. I testified in several cases, including Case No. U-9611, relating to the disposition of Midland proceeds, Case No. U-10040, the generic proceeding to examine accounting and ratemaking treatment of SFAS 106 Post-Retirement Benefits Other than Pensions, and submitted testimony in recent gas and electric rate cases, Cases U-15506 and U-15645, respectively.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to address (1) accounting for taxes associated with the equity component of allowance for funds used during construction ("AFUDC"),
(2) accounting for the Michigan Business Tax (“MBT”) that took effect in 2008, and (3)
the property tax rate determined for the 2010 test year.

Q. Are you sponsoring any exhibits?
A. Yes. I am sponsoring Exhibits A-71 (TJV-1) Property Tax Rate, and A-72 (TJV-2)
Development of Michigan Business Tax.

Q. Were these exhibits prepared by you or under your supervision?
A. Yes.

ACCOUNTING FOR AFUDC

Q. Please describe the Company’s current accounting for taxes associated with the equity
component of AFUDC.
A. MPSC Case No. U-5281 requires that a utility’s authorized overall cost of capital is the
basis for the AFUDC accrual rate. There is no gross-up in the equity component of the
AFUDC accrual rate for the revenue recovery of taxes. Accrual of AFUDC increases the
book basis of the underlying asset in excess of tax basis. FAS 109 “Accounting for
Income Taxes” requires recording a deferred income tax liability on this basis difference.

Prior to 2003, the company’s level of construction spending that qualified for
AFUDC treatment was insignificant. Since 2003, however, Consumers has accrued more
significant amounts of AFUDC equity for certain capital projects. AFUDC for our gas
operations for the period 2003-2008 averaged $886,000 per year, and the company
expects AFUDC to continue at about this higher level as we continue to invest in
Consumer Energy’s gas plant. The income tax effect of the equity component of
AFUDC, however, has been recognized as an expense instead of a FAS 109 related
regulatory asset.
The Company is requesting Commission approval to charge the income tax effect of the equity component of AFUDC as a FAS 109 regulatory asset, rather than deferred federal income tax expense, consistent both with Case No. U-10083 and FAS 109.

Q. What impact to ratemaking would result?
A. Deferred income tax expense would be reduced in the year in which AFUDC is recorded. Subsequently, the FAS 109 related regulatory asset and its offsetting deferred income tax liability would reverse over the book life of the underlying asset and thus offset each other for ratemaking purposes.

Q. Has the effect of this accounting change been reflected in the federal income tax expense filed by Consumers in this case?
A. No.

Q. What would be the impact on federal income tax expense in this case if the Commission approves this request?
A. If the Commission approves this request, the federal income tax expense as shown on line 12 of Exhibit A-8 (DSA-45) would be reduced by $234,000, from $29,119,000 to $28,885,000.

ACCOUNTING FOR THE MICHIGAN BUSINESS TAX

Q. Briefly describe, in general terms, the new Michigan Business Tax (MBT).
A. The MBT was enacted to replace the Michigan Single Business Tax (MSBT), effective January 1, 2008. The MBT is essentially a two-part tax, consisting of a tax imposed on the net taxable income of the business (referred to as the “business income tax”), and a tax imposed on the modified gross receipts of the business (referred to as the “modified gross receipts tax”). The MBT is further increased by a surcharge, and may be reduced
by tax credits, within limits, primarily geared toward companies investing and employing
in Michigan. For Consumers Energy, the credits that are of importance are those related
to compensation paid to Michigan employees and investment made in depreciable plant
and equipment located in Michigan.

Q. What type of tax is the MBT for accounting purposes?
A. Both components of the MBT, the business income tax and the modified gross receipts
tax, are considered income taxes under generally accepted accounting principles.
Therefore, Consumers Energy is required to apply the principles of Statement of
Financial Accounting Standards No. 109, “Accounting for Income Taxes” (“SFAS 109”) in
the reporting of the MBT in its financial statements.

SFAS 109 requires:

1. Accounting for MBT-related book/tax temporary differences that will reverse
after the MBT’s effective date of January 1, 2008.

2. Measurement of all cumulative Michigan book/tax temporary differences for the
Business Income Tax and the Modified Gross Receipts Tax.

3. Establishment of deferred MBT liabilities and assets for all book/tax temporary
differences.

4. Recording an offset to the establishment of deferred MBT tax liabilities and assets
by either:
   a. Income tax expense
   b. Deferred cost asset for regulated entities with assured future recovery from
   regulator applying the principles of SFAS 71, “Accounting for the Effects of Certain
   Types of Regulation.”
Q. Were deferred state income taxes recognized under the repealed MSBT?
A. No. Although book/tax temporary differences existed under the MSBT, the MSBT was not considered an income tax for accounting purposes; accordingly, deferred state income taxes were not recorded. As a result, when book/tax temporary differences under the MSBT originated or reversed, they flowed through in the determination of tax expense and cash tax payments. This accounting treatment was followed by the MPSC for regulatory accounting and ratemaking purposes.

Q. How should the MBT tax be accounted for?
A. As with the MSBT, book/tax temporary differences under the MBT that originate or reverse after January 1, 2008, should be flowed through until such time as normalization of the MBT is approved for regulatory accounting and rate-making purposes. Accordingly, in order to comply with SFAS 109, a Miscellaneous Deferred Debit account should be recognized in an amount to offset the deferred MBT liability for these cumulative deferred book/tax temporary differences. This is allowed under SFAS 71 and is consistent with the policy for ratemaking and accounting for income taxes that the Commission established in Case No. U-10083.

Q. What was the policy for ratemaking and accounting for income taxes that the Commission established in Case No. U-10083?
A. Upon implementation of SFAS 109 in 1993, the Commission order in No. U-10083 set forth the following income tax policy for ratemaking and accounting purposes:

1. Implemented comprehensive deferred income tax accounting as the preferred method of accounting for ratemaking purposes.
2. Provided general authorization to prospectively use deferred income tax accounting.

3. Provided regulatory asset/deferred cost authority for book/tax temporary differences as of the date of implementation to offset the recognition of any additional deferred tax liabilities. This authorization was necessary to comply with SFAS 109 requirements and allow temporary differences that previously flowed through net income to continue to flow through when the temporary differences reverse.

4. Provided assurance of continued recovery of regulatory assets/deferred costs and continued refunding of regulatory liabilities related to SFAS 109 through current ratemaking practices.

The income tax policy authorizations described above were necessary for a smooth transition to comprehensive deferred income tax accounting required by SFAS 109 and to provide both proper and consistent treatment of previously flowed through items for accounting and ratemaking. Implementing the new MBT has similar accounting and ratemaking requirements as the adoption of SFAS 109 for federal incomes taxes in 1993.

Q. Should the income tax policy authorized in Case No. U-10083 apply to the new MBT?

A. Yes. The order in Case No. U-10083 on its face appears to apply to all income taxes. There is no language in the order limiting this policy to federal income taxes. Moreover, the Special Instructions for Accumulated Deferred Income Taxes in the Commission’s Uniform System of Accounts specifically states: “The texts of these accounts are designed primarily to cover deferrals of Federal income taxes. However, they are also to be used when making deferrals of state and local income taxes.” The purpose of Case No. U-10083 was to provide an income tax policy for accounting and ratemaking to meet
the requirements of SFAS 109. SFAS 109 is the accounting pronouncement for all income taxes, regardless of whether they are federal or state. However, since the MBT is the first income tax imposed by Michigan since the order in Case No. U-10083, and the order was issued 15 years ago, the Commission should confirm in this case that the income tax policy for ratemaking and accounting authorized in Case No. U-10083 applies to the new MBT.

COMMISSION REQUEST REGARDING ACCOUNTING FOR TAXES

Q. What are you asking the Commission to confirm and authorize in the Final Order in this rate case regarding accounting for taxes?

A. I am requesting that the Commission confirm that the income tax policy authorized in Case No. U-10083 for ratemaking and accounting purposes will also apply to the new MBT. In addition, I am requesting the Commission authorize charging the income tax effect of the equity component of AFUDC as a FAS 109 regulatory asset. Specifically, the Commission’s order in this case should include the following authorizations:

1. Grant general authorization to use Accounts 190, 281, 282, and 283 offset by Deferred Income Tax Expense Account 410.1 or Credit Account 411.1 for book/tax temporary differences related to the MBT calculation originating on and after the date of the final order increasing rates in this case.

2. Grant general authorization to use Accounts 190, 281, 282, and 283 offset by a Miscellaneous Deferred Debit Account 186 for book/tax temporary differences related to the MBT calculation originating prior to the date of the final order increasing rates in this case.
3. Authorize assurance of recovery of the Miscellaneous Deferred Debit amounts in Account 186 related to the MBT calculation that will reverse in future years through current ratemaking practices.

4. Grant authority to charge the income tax effect of the equity component of AFUDC as a FAS 109 related regulatory asset, rather than deferred income tax expense, consistent both with Case No. U-10083 and FAS 109.

PROPERTY TAX RATE

Q. What is the Property Tax Rate for the 2010 test year?
A. As indicated on line 16 of Exhibit A-71 (TJV-1), the Property Tax Rate for the 2010 test year is 0.012051065.

Q. How did you calculate the Property Tax Rate for the 2010 test year?
A. The Property Tax Rate for the gas business was calculated using the Company’s 2010 Estimated Prorated Gas Property Tax Expense (line 10, Exhibit A-71 (TJV-1)) divided by the total of the estimated 2009 year-end plant-in-service (line 11, Exhibit A-71 (TJV-1)) plus one-half of the estimated Construction Work in Progress (line 14, Exhibit A-71 (TJV-1)).

Q. What is included in the Gas Property Taxes Paid – 2009 Estimate on the first line?
A. The Consumers Energy 2009 taxes paid of $44.7 million on behalf of the gas portion of the business represents estimated property taxes to be paid in 2009.
Q. What is included in the Estimated Gas Property Taxes on 2009 Plant Investment line?
A. The $4.0 million increase is the estimated property taxes on the 2009 estimated net additions that will be included in the 2010 property tax liability. This is calculated by taking the capital additions less retirements times the first year State Tax Commission multiplier table value to recognize a depreciation allowance, which is then multiplied by the statutory reduction of 50% of true cash value to get the assessed value, then multiplied by Consumers’ composite millage rate of 46.1666 to obtain the estimated tax amount. This calculation is shown on page 2 of Exhibit A-71 (TJV-1).

Q. What is included in the Estimated Gas Property Taxes on Real Property Taxable Value Increases – Inflation?
A. The zero increase for the Real Property Taxable Value relates to Article IX, Section 3 of the Michigan Constitution of 1963 allowing local assessors to raise real property taxable values by the lesser of 5% or the Consumer Price Index (CPI). For 2010, our property tax model assumes a CPI rate of .5%. This calculation is shown on page 3 of Exhibit A-71 (TJV-1).

Q. What is the result of including the Estimated Gas Property Taxes on Real Property Taxable Value Increase and Estimated Gas Property Taxes on 2009 Plant Investment have on the estimated 2010 property tax amount paid by the gas business?
A. The result of including these additional items is an estimated 2010 property tax amount to be paid for the gas business of $48.7 million.

Q. How is this paid amount converted to an expense amount?
A. Since the Company expenses property taxes based on the fiscal year of the taxing authorities, 56.95% of the 2009 estimated gas property tax payments for Consumers
Energy is added to the 2010 estimated gas payments since that amount will be expensed in 2010, while subtracting 56.95% of the 2010 estimated gas payments that will be expensed in 2011, arriving at a total 2010 property tax expense of $46.5 million.

Q. What is the next step in calculating the tax rate?

A. For the 2010 test year, property tax expense was prorated using a monthly budgeted sales percentage applied to the 2009 and 2010 estimated annual property tax expense amounts. The result of factoring property tax expense monthly for the test year is a Prorated Gas Property Tax Expense of $45.5 million. The Prorated Property Tax Expense for the test year is divided by the 2009 estimated year-end plant in service amount plus one-half of construction work in progress to arrive at an average tax rate of 0.012051065.

MICHIGAN BUSINESS TAX EXPENSE

Q. What is the Michigan Business Tax Expense for the 2010 test year?

A. As indicated on line 70 of Exhibit A-72 (TJV-2), total MBT expense for test year 2010 in this case is $4,449,000, consisting of $5,683,000 of current MBT, as shown on line 58 of Exhibit A-72 (TJV-2), offset by ($1,234,000) of deferred MBT, as shown on line 69 of Exhibit A-72 (TJV-2).

Q. Does this conclude your testimony?

A. Yes.
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
distribution of natural gas and for other relief

Case No. U-15986

__________________________________________

DIRECT TESTIMONY

OF

THOMAS A. YEHL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May, 2009
Q. Please state your name and business address.
A. My name is Thomas A. Yehl. My business address is One Energy Plaza, Jackson, Michigan.

Q. By whom are you employed?
A. I am employed by Consumers Energy Company (“Consumers Energy” or “Company”).

Q. What is your position with Consumers Energy?
A. I am a Principal Rate Analyst in the Rates and Regulation Department, where I am a member of the Cost and Pricing section.

Q. Please state your educational background.
A. I graduated from Central Michigan University in May of 1974 with a Bachelor of Science Degree in Mathematics. In addition, I have attended a number of courses on utility ratemaking.

Q. What is your business experience?
A. I have spent my entire career within the regulatory areas of Consumers Energy Company. In May 1974, I joined the Company as a Graduate Rate Analyst in the Rates and Rate Research Department. In January 1975, I was promoted to Associate Rate Analyst, and in June 1977, I was promoted to Rate Analyst. My primary responsibilities were the preparation of cost-of-service and rate design studies for both general gas rate case filings before the Michigan Public Service Commission (“MPSC”) and wholesale for resale electric rate filings before the Federal Energy Regulatory Commission (“FERC”). In November 1981, I was promoted to General Rate Analyst and transferred to the Rate Administration Section of the Rates and Rate Research Department.
responsibilities involved participation in region rate audits, typical bill analysis, and
day-to-day rate application issues.

In June 1984, I joined the Revenue Requirements Department where I was
responsible for the development of various studies which determined the Company's
revenue needs for both electric and gas general rate case filings before the MPSC and the
FERC. My specific responsibilities also included the preparation of a number of monthly
rate-of-return studies.

In November 1989, I rejoined the Rates and Rate Research Department as a
member of the Gas Rates Section, where my responsibilities included the preparation of
gas rate design studies and all administrative aspects of the Company's gas transportation
program. In July 1991, I was assigned to the Rates Section of the newly formed Rates
and Regulatory Affairs Department. My responsibilities were increased to also include
electric rate design studies and other ratemaking projects. In February 2001, I was
promoted to Senior Rate Analyst. In October 2003, the department name was changed to
Rates and Business Support Department.

In April 2004, I was promoted to Principal Rate Analyst. As Principal Analyst, I
am responsible for the preparation of electric and gas cost-of-service studies that are
utilized to support the electric and gas rate design filed in the Company’s electric and gas
rate case proceedings. In January 2007, the department name was changed to Rates and
Regulation Department, and the Cost Analysis and Pricing functions were combined to
form the Cost and Pricing section.
Q. Have you previously testified in any regulatory proceedings before the MPSC?

A. In Case No. U-10554, I testified to the proper surcharge level necessary for the Company to collect the incentive associated with the Company's Demand Side Management program. In Case No. U-11662, I testified to the proper surcharge level required by the Company to collect the nuclear decommissioning revenue needed to fund the eventual decommissioning of the Company's nuclear plants. In Case No. U-12970, I presented unbundled electric rates for the Company’s residential, commercial, and industrial tariffs. In Case No. U-14150, I again presented testimony as to the proper level of the Company’s nuclear decommissioning surcharges. In Case No. U-14347 and Case No. U-15245, which were electric rate filings, I was the cost-of-service witness. Most recently, I was the cost-of-service and rate design witness in Case No. U-15506, which was a gas rate filing.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the Company’s historical and test year gas cost-of-service studies by rate class.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring the following exhibits:

Exhibit A-73 (TAY-1), Schedule F-1, 2008 Historical Gas Cost-of-Service Study; and

Exhibit A-74 (TAY-2), Schedule F-1, 2010 Test Year Gas Cost-of-Service Study

Q. Were these exhibits prepared by you or under your supervision?

A. Yes, they were.
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 cost-of-service studies I have filed in this
case serve two purposes. The historical COSS is used to determine the relative
collection to earnings for each of the Company’s gas rate classes, while the test year
COSS is used as a guide to design the Company’s proposed gas rate structure.

Q. Please explain what is involved in performing a COSS.
A. A COSS compares how costs are incurred with how costs are recovered for a designated
time period. Each cost item is allocated among the rate classes for whose benefit the cost
was incurred. Before any allocations can be made, the costs must be separated into
categories that relate to production, storage, transmission, and distribution. This
separation of costs is referred to as functionalization. Once these costs are functionalized,
they are further classified as transmission-related, high pressure distribution-related, non
high pressure distribution-related, or customer-related. Only after the costs are
functionalized and classified into groups can they be allocated to the various rate classes.

Q. Is Consumers Energy proposing any changes to how it prepares its cost studies?
A. No. Both the historical and test-year cost studies were prepared using the methods
previously approved by this Commission.

Q. Please describe Exhibit A-73 (TAY-1).
A. Exhibit A-73 (TAY-1) is a four page exhibit that summarizes the 2008 Historical Gas
Cost-of-Service Study ("2008 Historical COSS"). Page 1 of the exhibit is a summary that
shows the Company’s total gas rate base on line 12, and also identifies the revenues and
expenses necessary to calculate adjusted net operating income, which can be found on
line 11, for the Company’s major tariff classifications. Page 1 also calculates rate of return on rate base on line 13 and index of return on line 14. Across the top of page 1 are the Company’s major tariff classifications to which the total cost to serve is allocated. Total Company gas information reported for 2008 is found in column (c). Columns (d) through (j) show the cost to serve for each of the Company’s major tariff classifications.

Page 2 of the exhibit details each allocation factor that has been utilized for cost allocation in the 2008 Historical COSS. Page 3 shows the development of total gas rate base, while page 4 details total gas O&M expense.

Q. How was the reported 2008 gas information that appears in column (c) of Exhibit A-73 (TAY-1) determined?
A. Total plant investment, revenues, expenses, and net operating income are based on 12 months ended December 31, 2008. All information was extracted from Company records.

Q. Please describe the results of the 2008 Historical COSS.
A. The 2008 Historical COSS shows the Company’s total rate base, rate of return on rate base, and index of return by rate schedule for 2008. It indicates that the residential and general service rate schedules, as well as Rate ST and Rate LT, are near their cost based levels. However, it also indicates that Rate XLT is significantly below its cost based level.

Q. What indicates whether a rate schedule is or is not at the cost based level?
A. The index of return, which is found on page 1, line 14, in the 2008 Historical COSS, provides a gauge to determine if a rate schedule is cost based. If the index for a particular
rate schedule shows 100 basis points, then the revenues collected from customers served under the schedule equal the costs of providing their service.

Q. What if the index is above or below the 100 basis point level?
A. If the index of return for a particular rate schedule is above 100 basis points, then the customers served under the rate schedule are contributing more revenue than is necessary to cover their cost to serve. Conversely, if the index is below 100 basis points, then customers are not contributing enough revenue to cover their cost to serve. As such, the 2008 Historical COSS indicates that the GS-2 and GS-3 sales rate schedules and the ST and LT transportation rate schedules are above the cost based level since they are above 100 basis points. Residential, Rate GS-1 and Rate XLT are below the cost based level because the indices are at 97, 95, and 60 basis points respectively.

Q. Please describe Exhibit A-74 (TAY-2).
A. This exhibit summarizes the results of the 2010 Test Year Gas Cost-of-Service Study (“2010 Test Year COSS”). Exhibit A-74 (TAY-2) is a six-page exhibit that mirrors the 2008 Historical COSS. However, the 2010 Test Year COSS incorporates the test year changes as sponsored by Company witnesses into the 2008 Historical COSS, and the 2010 Test Year COSS was prepared utilizing cost allocation methodology consistent with past MPSC practice. Company witness Alfred calculates the revenue deficiency, which can be found on page 1, line 17, column (c) of Exhibit A-74 (TAY-2). The 2010 Test Year COSS then calculates the total revenue deficiency or sufficiency by rate class on page 1, line 17, columns (d) through (j) of Exhibit A-74 (TAY-2). Company witness Pender will utilize the 2010 Test Year COSS as a tool in designing the Company’s proposed rates in this proceeding.
Q. Does this conclude your testimony in this proceeding?
A. Yes, it does.