Consumers Energy
Count on Us

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September 28, 2012

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
4300 W. Saginaw
Lansing, MI 48917

RE: Case No. U-17133 In the Matter of the Application of Consumers Energy Company for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2013

Dear Ms. Kunkle:

Included in this electronic file are Consumers Energy Company's Application, Testimony and Exhibits of Consumers' witnesses Shawn D. Burgdorf, Natalie N. Busak, Jim K. Chilson, II, David B. Kehoe, David F. Ronk, Jr., Sara T. Walz and Lincoln D. Warriner. Also included is a Proof of Service. This is a paperless filing and is therefore being filed only in a PDF format.

Sincerely,

Digitally signed by John C. Shea
Date: 2012.09.28 14:04:18 -04'00'

John C. Shea

cc: Parties to Case No. U-16890

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2013.	))))))	Case No. U-17133

APPLICATION

Consumers Energy Company ("Consumers Energy") hereby applies for approval of a power supply cost recovery ("PSCR") plan and monthly PSCR factors for the period January-December 2013. In support of this application, Consumers Energy says as follows:

1. Consumers Energy is a public utility engaged in, among other things, the generation, purchase, distribution and sale of electric energy to approximately 1.8 million retail electric customers in the lower peninsula of the State of Michigan.

2. Consumers Energy's retail electric business is subject to the jurisdiction of the Michigan Public Service Commission (the "Commission") pursuant to certain provisions of 1939 PA 3, as amended by various acts, including 1982 PA 304 and 2000 PA 141, MCL 460.1 *et seq*.; 1909 PA 106, as amended, MCL 460.551 *et seq*.; 1909 PA 300, as amended, MCL 462.2 *et seq*.; and 2008 PA 286, MCL 460.4a *et seq*.

3. This application is filed pursuant to MCL 460.6j, and Consumers Energy's Rule C8. MCL 460.6j authorizes the Commission to approve a power supply cost recovery clause for electric utilities such as Consumers Energy. Company Rule C8 sets forth the Company's Power Supply Cost Recovery clause, which was approved by Commission orders issued October 18, 1983 in Case No. U-7511, October 9, 2007 in Case No. U-15152 and June 7, 2012 in Case No. U-16794.

4. Rule C8 of Consumers Energy's electric tariffs requires the Company to file a PSCR plan, to request approval of specific PSCR factors for a future 12-month period, and to provide a five-year forecast. Accompanying this Application are the testimony and exhibits of witnesses for Consumers Energy that meet the requirements of Rule C8 with respect to the above-referenced time period. This prefiled testimony and exhibits include an evaluation and conclusions as to the reasonableness and prudence of the forecasted costs of fuel and purchased and net interchange power. Also included in these materials is a five-year forecast of the power supply requirements of Consumers Energy's customers, anticipated sources of supply, and projections of power supply costs.

5. As more fully described in the accompanying testimony and exhibits, Consumers Energy seeks approval to apply, for each month in calendar year 2013, a uniform maximum PSCR factor of $0.00194 per kWh for all classes of customers.

6. The accompanying testimony and exhibits are an integral part of this Application and the relief described therein is incorporated by reference in this Application as if fully set forth herein.

WHEREFORE, Consumers Energy Company respectfully requests that the Commission grant the following relief:

A. Issue a prompt notice commencing hearings on the relief sought herein;

B. Approve for 2013 a maximum monthly PSCR factor of $0.00194 per kWh for all classes of customers as set forth herein and more fully explained in the accompanying testimony;

C. Approve the PSCR plan for 2013 described in this Application; and

D. Grant such further and additional relief as may be lawful and appropriate.

Respectfully submitted,

Consumers Energy Company

Date: September 28, 2012

By: Digitally signed by Timothy J. Sparks
Date: 2012.09.28 14:10:18 -04'00'

Timothy J. Sparks
Vice President of Energy Supply Operations

Digitally signed by John C. Shea
Date: 2012.09.28 14:20:42 -04'00'

John C. Shea (P36854)
Attorney for Consumers Energy Company
One Energy Plaza
Jackson, Michigan 49201
(517) 788-2112

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2013.	))))))	Case No. U-17133

VERIFICATION

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Timothy J. Sparks, being first duly sworn, deposes and says that he is the Vice President of Energy Supply Operations of Consumers Energy Company; that he has executed the foregoing Application for and on behalf of Consumers Energy Company; that he has read the foregoing Application and is familiar with the contents thereof; that the facts contained therein are true, to the best of his knowledge and belief; and that he is duly authorized to execute such Application on behalf of Consumers Energy Company.

Tim Sparks Digitally signed by Timothy J. Sparks
Date: 2012.09.28 14:29:39 -04'00'

Timothy J. Sparks,
Vice President of Energy Supply Operations

Subscribed and sworn to before me this 28th day of September, 2012.

Sharon K. Davis Digitally signed by Sharon K. Davis
Date: 2012.09.28 14:38:52 -04'00'

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

ap092812-225

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2013.	))))))	Case No. U-17133

DIRECT TESTIMONY

OF

SHAWN D. BURGDORF

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

QUALIFICATIONS

Q. Please state your name and business address.

A. Shawn D. Burgdorf, 1945 W. Parnall Rd, Jackson, Michigan.

Q. By whom are you employed?

A. Consumers Energy Company ("Consumers Energy" or "Company").

Q. What is your position with Consumers Energy?

A. I am a General Engineer in the Transmission and Regulatory Strategies Section of Energy Supply Operations.

Q. Please state your educational background and business experience.

A. I received a Bachelor of Science degree in mechanical engineering in 2005 from the University of Michigan. From January 2006 until the present, I have been employed by Consumers Energy. Initially, I worked as a General Engineer in the Company's production cost modeling group. In that position I supported the development of power supply forecasts. I held this position until August 2009 at which time I transferred into my current position within the Transmission and Regulatory Strategies Section of Energy Supply Operations. In this position, I am responsible for monitoring and analyzing the filings by the Midwest Independent Transmission System Operator, Inc. ("MISO") at the Federal Energy Regulatory Commission ("FERC"). In addition, I support the Company's involvement in stakeholder and transmission planning activities at MISO, FERC, and Michigan Public Service Commission ("MPSC" or "Commission"). I am also responsible for forecasting future transmission and certain energy market related costs expected to impact the Company.

Q. Have you ever appeared in any proceedings before the Commission?

A. Yes. I have provided testimony in:

- MPSC Case No. U-16149 regarding the Company's 2010 – 2011 Gas Cost Recovery ("GCR") Plan;
- MPSC Case No. U-16485 regarding the Company's 2011 – 2012 Gas Cost Recovery ("GCR") Plan;
- MPSC Case No. U-16924 regarding the Company's 2012 – 2013 Gas Cost Recovery ("GCR") Plan; and
- MPSC Case No. U-16890 regarding the Company's 2012 Power Supply Cost Recovery ("PSCR") Plan.

PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to: 1) identify certain transmission and energy market expenses for 2013 for which the Company seeks recovery in the Company's 2013 PSCR plan; 2) identify generation-related credits to total PSCR costs relating to Schedule 2 Reactive revenues; and 3) describe the Company's effort to manage its transmission related costs.

Q. Are you sponsoring any exhibits in connection with your testimony?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-1 (SDB-1)	Transmission and Energy Market Administration Expenses

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

TRANSMISSION AND ENERGY MARKET EXPENSE

Q. What transmission and energy market expense does the Company seek recovery for in the Company's 2013 PSCR plan?

A.. The Company seeks to recover all of the charges imposed on the Company under MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") which is filed with and approved by FERC.

Q. Has the Commission previously approved the recovery of Transmission, Energy and Operating Reserve Market ("Market") costs through the PSCR process?

A. Yes. The Commission approved recovery of expenses incurred under MISO's Tariff in the Company's PSCR factor most recently in the 2011 PSCR plan case U-16432. I am informed by counsel that the Commission's actions with respect to transmission expenses was approved by the Michigan Supreme Court in its order in *Attorney General v Michigan Public Service Commission*, 483 Mich 998 (May 1, 2009).

Q. Are the rates assessed and revenues distributed by MISO subject to FERC review?

A. Yes. Thus, all of the charges incurred and revenues received through MISO by the Company are based on the FERC-approved tariff.

Q. Please list each transmission and energy market charge that has been projected for 2013 in the Company's total transmission costs.

A. The transmission and energy-market-related charges included in the total transmission costs projected for 2013 (and shown in Exhibit A-1 (SDB-1) page 1 of 5) are incurred as a result of the mandated expenses charged to Consumers Energy by MISO pursuant to MISO Schedules 1, 2, 9, 10, 10-FERC, 16, 17, 24, 26 and 26-A. The charges imposed pursuant to these schedules are discussed more fully below.

Q. Has the Company forecasted other MISO charges?

A. Yes. As discussed by Mr. Ronk, the impact of other MISO charges is included in the projection of energy costs.

Q. Are your projections based on the demand and sales information provided by Company witness Warriner?

A. Yes.

Q. Please describe the MISO Schedule 1 rate and the forecasted cost of this expense.

A. MISO Schedule 1 is a service required to schedule the movement of power through, out of, within or into a control area and is provided by the transmission operators within the control area and MISO. The rate for this service is a MISO-wide rate. Applying this rate to the Company's forecasted monthly coincident peak produces the Company's forecasted expense. This forecasted expense for each plan year is shown on Exhibit A-1 (SDB-1), line 15.

Q. Please describe the MISO Schedule 2 rate and forecasted cost of this expense.

A. MISO Schedule 2 is an ancillary service required to be provided by MISO for Reactive Supply and Voltage Control from Generation Sources. The rate for this service is a pricing zone wide rate. Applying the applicable pricing zone rate to the Company's forecasted monthly coincident peak produces the Company's forecasted expense. This forecasted expense for each plan year is shown on Exhibit A-1 (SDB-1), line 16.

Q. Please describe the MISO Schedule 9 rate and the forecasted cost of this expense.

A. MISO Schedule 9 is the network transmission service rate that applies to the Company's entire retail load within the MISO footprint. MISO utilizes the "license plate" rate approach, which means that the rate applicable to each customer is that of the transmission owner(s) in the pricing zone where the load is located. The Company pays the rate for the Michigan Joint Zone ("MJZ"). This rate is calculated per MISO's Attachment O and is updated biannually. The Company's forecasted expense for each plan year is shown on Exhibit A-1 (SDB-1), line 17.

Q. Please describe the MISO Schedule 10 rates and forecasted cost of this expense.

A. MISO Schedule 10 recovers MISO expenses associated with the operation of MISO in the provision of transmission service within the MISO footprint. MISO assesses Schedule 10 with two rates. The first rate is applied to peak load at a 100% load factor. The Company's forecasted expense for each plan year for this portion of Schedule 10 is shown on Exhibit A-1 (SDB-1) line 18. The second rate is applied to actual volume of MWh of transmission service received. The Company's forecasted expense for each plan year for this portion of Schedule 10 is shown on Exhibit A-1 (SDB-1), line 19.

Q. Please describe the MISO Schedule 10-FERC rate and the forecasted cost of the expense.

A. MISO Schedule 10-FERC is utilized to allocate to MISO's wholesale transmission customers the amount of the FERC Annual Fee that MISO is assessed. The FERC Annual Fee is designed to reimburse the federal government for all of the costs incurred by the FERC under Parts II and III of the Federal Power Act and related statutes per 18 CFR Part 382. The Company's forecasted expenses for each plan year are shown on Exhibit A-1 (SDB-1), line 20.

Q. Please describe the MISO Schedule 16 rate and forecasted cost of expense.

A. MISO Schedule 16 is designed to recover MISO administrative service costs associated with MISO Financial Transmission Rights ("FTR") process. In forecasting the Schedule 16 expense, I multiplied the Company's monthly coincident peak load at a 100% load factor against the MISO budgeted Schedule 16 rate to produce the expected expense. The Company's forecasted expenses for each plan year are shown on Exhibit A-1 (SDB-1) line 21.

Q. Please describe the MISO Schedule 17 rate and forecasted cost of expense.

A. MISO Schedule 17 is designed to recover MISO administrative service costs associated with the Midwest Energy and Operating Reserves Market. The rate is charged to all injections and withdrawals in the market. The Company's forecasted expenses for each plan year are shown on Exhibit A-1 (SDB-1) on line 22.

Q. Please describe the MISO Schedule 24 rate and forecasted cost of expense.

A. MISO Schedule 24 is a Control Area Operator Cost Recovery charge used to recover Control Area costs incurred with the implementation of the Market. This rate is charged on the same basis as Schedule 17. The Company's forecasted expenses for each plan year are shown on Exhibit A-1 (SDB-1) on line 23.

Q. Please describe the MISO Schedule 26 rate and forecasted cost of expense.

A. MISO Schedule 26 is a Network Upgrade Charge from MISO's Transmission Expansion Plan ("MTEP"). This schedule is applied on the same basis as Schedule 9. It reflects the sharing of MTEP project costs as allocated according to Attachment FF of the MISO Tariff. The Company's forecasted expenses for each plan year are shown on Exhibit A-1 (SDB-1) line 24.

Q. Please describe the MISO Schedule 26-A rate and forecasted cost of expenses.

A. MISO Schedule 26-A is the Multi-Value Project Usage Rate ("MUR") and is a MISO System-wide rate charged to Monthly Net Actual Energy Withdrawals, certain Export Schedules, and Through Schedules. The rate is calculated using the formula included in

Attachment MM of the Tariff. The charges under this Schedule 26-A shall be in addition to any charges under Schedules 7, 8, 9, and 26. Grandfathered Agreements will not be charged this Schedule. The Company's forecasted expenses for each plan year are shown on Exhibit A-1 (SDB-1) line 25.

Q. What is the total amount of transmission and energy market expenses that you propose to add to the total power costs in each year of the PSCR plan?

A. Each of the expenses described above, as well as the total expenses for each plan year, is identified on Exhibit A-1 (SDB-1). The total cost for the first year of the plan equals $321,184,422 and can be found on Line 29, column (o) of page 1 of Exhibit A-1 (SDB-1). It is composed of $314,011,368 of transmission expenses (Line 27, column (o)) and $7,173,054 of energy market administration expenses (Line 28, column (o)).

SCHEDULE 2 REACTIVE REVENUE REQUIREMENT CREDIT

Q. What is the basis for proposing to credit reactive revenue requirements revenues against total PSCR costs?

A. Consumers Energy provides generation-related reactive services that are necessary for the transmission of power. Consumers Energy incurs an expense under the MISO Tariff when it receives reactive service within Michigan Joint Zone pricing zone. The Company believes that the revenues received from this service should be credited against total power costs for Consumers Energy's retail customers via the PSCR factor, since the expense for the service is included in the PSCR.

Q. Have you identified the revenues the Company expects to receive in 2013 from Schedule 2?

A. Yes. The Company expects to receive $19,706,000. This amount is composed of the FERC approved revenue requirements established in FERC Docket Nos. OA96-77 and ER04-1110.

COMPANY ACTIVITIES RELATED TO TRANSMISSION COST MANAGEMENT

Q. Are there any additional items that may impact your forecast?

A. Yes. Among the more significant items being discussed and/or pending before FERC are methods for funding the MISO transmission system expansion (Regional Expansion Criteria and Benefits or "RECB") and cross-border allocation of costs with PJM regarding both transmission system expansion and the elimination of the Regional Through and Out Rate on transactions that cross the MISO-PJM Border. The uncertain outcome of the Multi-Value Project court appeal as well as the impact of FERC Order 1000 will most likely have a future financial impact.

Q. How have you forecasted the potential changes in costs and revenues from these items?

A. I continue to forecast cost as if the currently filed MISO tariff remained in effect through the planning period.

Q. Does the Company take actions to mitigate transmission related costs?

A. Yes. The Company actively participates in the transmission provider's stakeholder process dealing with transmission planning and project approval. It is primarily through this stakeholder process that the Company works to assure new transmission investments are justified and allocated on a cost causation basis. Additionally, the Company actively monitors and intervenes in tariff filings by MISO and transmission owners to assure that the new tariff provisions are in compliance with FERC policy and are based on cost causation principles.

Q. Is the Company involved in other activities to mitigate transmission related costs?

A. Yes. Under the FERC-approved MISO tariff, transmission owners recover their Operations and Maintenance ("O&M"), Depreciation, and Tax expenses, as well as a Return on Investment through an "Attachment O" formula rate that utilizes the actual costs incurred and reported on the transmission owners' FERC Form 1 reports. The Company actively reviews the "Attachment O" rates of the Michigan Joint Zone transmission owners to assure the application of the formula is consistent with the tariff.

Q. Can you identify some of MISO stakeholder groups the Company actively follows that impact transmission expenses?

A. Yes. The Company has been very active in MISO's transmission related groups such as the East Subregional Planning Meetings, Michigan Technical Study Task Force, Planning Advisory Committee, Planning Subcommittee, Advisory Committee, Regional Expansion Criteria and Benefits Task Force and the MISO Board of Directors System Planning Committee. The Company's focus is to monitor and assure new transmission projects are justified and costs are allocated according to cost causation principles.

Q. How does participating in these groups impact the Company's transmission expense?

A. By actively participating in the stakeholder process regarding proposed transmission projects, the Company can independently validate the need for the project before the project is approved by the MISO Board of Directors in the MTEP. If the Company does not believe a project is needed, it can raise issues with MISO before the project is approved.

Q. Does that mean that MISO will reject a project Consumers Energy or another customer or interested party does not believe is needed?

A. No. Third party input to MISO and transmission owners is advisory only.

Q. What other strategies has the Company used to manage the cost of transmission for its customers?

A. Consumers Energy monitors and intervenes in FERC proceedings involving MISO and the transmission owners providing service to the Company.

Q. What was the purpose of these interventions?

A. The Company generally intervenes in transmission filings to attempt to ensure that issues are resolved according to FERC policy. When the Company believes the filings at FERC will have a negative impact on the Company's transmission cost and are not in accordance with FERC policy, the Company will protest.

Q. Are there other activities Consumers Energy has been engaged in regarding transmission planning and cost allocation?

A. Yes. Consumers Energy is a founding member and actively participates with other companies through the Coalition for Fair Transmission Policy ("CFTP") to develop and advocate industry positions at the federal level supporting policies on transmission planning and cost allocation. The Company is also an active participant within the MISO Northeast Transmission Customers which consists of the Michigan Attorney General, the Association of Businesses Advocating Tariff Equity ("ABATE"), Consumers Energy Company, Detroit Edison Company, the Michigan Municipal Electric Association ("MMEA"), and the Michigan Public Power Agency ("MPPA"). The group has protested and advocated for fair transmission cost allocation as it pertains to the Multi-Value Project filing by MISO.

Q. Does this conclude your direct written testimony?

A. Yes, it does.

STATE OF MICHIGAN

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In the matter of the application of CONSUMERS ENERGY COMPANY for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2013	))))))	Case No. U-17133

EXHIBIT

OF

SHAWN D. BURGDORF

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

Consumers Energy Company

2013 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper SDB-1	5,529	5,339	5,142	4,811	5,739	6,957	7,567	7,765	6,428	5,348	5,325	5,694	**71,644**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper SDB-3	3,174,538	2,817,444	2,917,996	2,742,351	2,865,210	3,168,103	3,494,290	3,519,120	2,968,482	2,990,673	2,823,423	3,215,455	**36,697,085**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	385.0317	385.0317	385.0317	385.0317	385.0317	385.0317	385.0317	385.0317	385.0317	385.0317	385.0317	385.0317	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	2,827.8046	2,827.8046	2,827.8046	2,827.8046	2,827.8046	2,838.2465	2,838.2465	2,838.2465	2,838.2465	2,838.2465	2,838.2465	2,838.2465	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-6	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper SDB-6	0.0734	0.0734	0.0734	0.0734	0.0734	0.0734	0.0734	0.0734	0.0734	0.0734	0.0734	0.0734	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-6	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	909.1328	909.1328	909.1328	909.1328	909.1328	909.1328	909.1328	909.1328	909.1328	909.1328	909.1328	909.1328	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	0.1741	0.1741	0.1741	0.1741	0.1741	0.1741	0.1741	0.1741	0.1741	0.1741	0.1741	0.1741	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 359,159	$ 346,817	$ 334,020	$ 312,518	$ 372,800	$ 451,920	$ 491,546	$ 504,407	$ 417,557	$ 347,401	$ 345,907	$ 369,877	**$ 4,653,930**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,128,841	2,055,684	1,979,833	1,852,388	2,209,697	2,678,666	2,913,535	2,989,772	2,474,984	2,059,150	2,050,294	2,192,371	**27,585,214**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	15,634,931	15,097,649	14,540,571	13,604,568	16,228,770	19,745,681	21,477,011	22,038,984	18,244,249	15,178,942	15,113,663	16,160,976	**203,065,994**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	219,254	191,230	203,907	184,627	227,581	266,982	300,071	307,923	246,681	212,076	204,352	225,797	**2,790,480**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	233,011	206,800	214,181	201,289	210,306	232,539	256,481	258,303	217,887	219,515	207,239	236,014	**2,693,566**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	144,949	128,644	133,236	125,216	130,825	144,656	159,549	160,683	135,541	136,554	128,917	146,818	**1,675,589**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	41,136	35,878	38,256	34,639	42,698	50,090	56,298	57,772	46,282	39,789	38,340	42,363	**523,542**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	488,879	433,886	449,371	422,322	441,242	487,888	538,121	541,944	457,146	460,564	434,807	495,180	**5,651,351**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	86,347	76,634	79,369	74,592	77,934	86,172	95,045	95,720	80,743	81,346	76,797	87,460	**998,161**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,026,595	4,853,860	4,674,761	4,373,838	5,217,513	6,324,837	6,879,408	7,059,416	5,843,906	4,862,042	4,841,132	5,176,602	**65,133,911**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	552,663	490,496	508,001	477,422	498,811	551,543	608,329	612,652	516,790	520,653	491,537	559,786	**6,388,684**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 24,301,403**	**$ 23,373,180**	**$ 22,590,509**	**$ 21,133,865**	**$ 25,098,305**	**$ 30,398,823**	**$ 33,087,930**	**$ 33,934,140**	**$ 28,099,594**	**$ 23,538,335**	**$ 23,385,042**	**$ 25,070,241**	**$ 314,011,368**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**616,362**	**546,399**	**566,997**	**531,553**	**561,874**	**624,151**	**689,464**	**695,436**	**584,171**	**581,699**	**549,944**	**625,004**	**7,173,054**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 24,917,765**	**$ 23,919,579**	**$ 23,157,507**	**$ 21,665,419**	**$ 25,660,180**	**$ 31,022,974**	**$ 33,777,394**	**$ 34,629,576**	**$ 28,683,764**	**$ 24,120,034**	**$ 23,934,986**	**$ 25,695,245**	**$ 321,184,422**

Consumers Energy Company

2014 Transmission and Energy Market Administration Expenses

Case No.: 2013 PSCR Plan Case
Witness: SDBurgdorf
Exhibit: A-1 (SDB-1)
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Date: September 2012

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper SDB-1	5,686	5,494	5,300	4,966	5,880	7,109	7,717	7,907	6,580	5,507	5,476	5,861	**73,483**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper SDB-3	3,232,475	2,874,640	2,970,801	2,806,799	2,926,234	3,229,770	3,559,540	3,583,327	3,033,707	3,051,770	2,885,092	3,275,819	**37,429,974**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	376.1842	376.1842	376.1842	376.1842	376.1842	376.1842	376.1842	376.1842	376.1842	376.1842	376.1842	376.1842	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	2,857.0969	2,857.0969	2,857.0969	2,857.0969	2,857.0969	2,867.1161	2,867.1161	2,867.1161	2,867.1161	2,867.1161	2,867.1161	2,867.1161	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-6	0.0520	0.0520	0.0520	0.0520	0.0520	0.0520	0.0520	0.0520	0.0520	0.0520	0.0520	0.0520	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper SDB-6	0.0719	0.0719	0.0719	0.0719	0.0719	0.0719	0.0719	0.0719	0.0719	0.0719	0.0719	0.0719	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-6	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	1,182.0882	1,182.0882	1,182.0882	1,182.0882	1,182.0882	1,182.0882	1,182.0882	1,182.0882	1,182.0882	1,182.0882	1,182.0882	1,182.0882	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	0.3528	0.3528	0.3528	0.3528	0.3528	0.3528	0.3528	0.3528	0.3528	0.3528	0.3528	0.3528	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 369,357	$ 356,885	$ 344,283	$ 322,587	$ 381,960	$ 461,794	$ 501,289	$ 513,632	$ 427,431	$ 357,730	$ 355,716	$ 380,725	**$ 4,773,390**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,138,983	2,066,756	1,993,776	1,868,131	2,211,963	2,674,294	2,903,014	2,974,489	2,475,292	2,071,646	2,059,985	2,204,816	**27,643,145**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	16,245,453	15,696,890	15,142,614	14,188,343	16,799,730	20,382,328	22,125,535	22,670,287	18,865,624	15,789,208	15,700,328	16,804,167	**210,410,507**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	219,980	191,982	205,046	185,927	227,485	266,161	298,555	305,906	246,355	213,055	205,021	226,750	**2,792,225**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	232,415	206,687	213,601	201,809	210,396	232,220	255,931	257,641	218,124	219,422	207,438	235,531	**2,691,215**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	147,595	131,256	135,647	128,158	133,612	147,471	162,529	163,615	138,519	139,344	131,733	149,574	**1,709,053**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	38,073	33,228	35,489	32,180	39,372	46,066	51,673	52,945	42,638	36,875	35,484	39,245	**483,270**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	459,011	408,199	421,854	398,565	415,525	458,627	505,455	508,832	430,786	433,351	409,683	465,166	**5,315,056**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	87,923	78,190	80,806	76,345	79,594	87,850	96,819	97,466	82,517	83,008	78,475	89,102	**1,018,095**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	6,721,354	6,494,393	6,265,068	5,870,250	6,950,679	8,403,465	9,122,175	9,346,772	7,778,140	6,509,760	6,473,115	6,928,219	**86,863,389**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	1,140,471	1,014,221	1,048,148	990,286	1,032,424	1,139,517	1,255,865	1,264,258	1,070,342	1,076,715	1,017,909	1,155,764	**13,205,920**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 27,217,608**	**$ 26,161,070**	**$ 25,350,183**	**$ 23,757,491**	**$ 27,950,249**	**$ 33,709,251**	**$ 36,626,893**	**$ 37,498,598**	**$ 31,221,828**	**$ 26,378,881**	**$ 26,153,245**	**$ 28,087,547**	**$ 350,112,843**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**585,008**	**519,617**	**538,148**	**507,090**	**534,491**	**592,543**	**653,947**	**659,244**	**555,942**	**553,234**	**523,642**	**593,514**	**6,816,421**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 27,802,617**	**$ 26,680,687**	**$ 25,888,331**	**$ 24,264,581**	**$ 28,484,740**	**$ 34,301,794**	**$ 37,280,840**	**$ 38,157,843**	**$ 31,777,769**	**$ 26,932,115**	**$ 26,676,887**	**$ 28,681,061**	**$ 356,929,265**

Consumers Energy Company

Case No.: 2013 PSCR Plan Case
Witness: SDBurgdorf
Exhibit: A-1 (SDB-1)
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2015 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper SDB-1	5,782	5,581	5,390	5,054	5,931	7,197	7,802	7,947	6,663	5,593	5,568	5,949	**74,457**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper SDB-3	3,285,298	2,928,394	3,020,853	2,854,766	2,971,563	3,277,507	3,604,383	3,628,532	3,082,035	3,092,341	2,926,676	3,316,474	**37,988,822**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	371.5518	371.5518	371.5518	371.5518	371.5518	371.5518	371.5518	371.5518	371.5518	371.5518	371.5518	371.5518	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	2,862.1016	2,862.1016	2,862.1016	2,862.1016	2,862.1016	2,851.3673	2,851.3673	2,851.3673	2,851.3673	2,851.3673	2,851.3673	2,851.3673	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-6	0.0527	0.0527	0.0527	0.0527	0.0527	0.0527	0.0527	0.0527	0.0527	0.0527	0.0527	0.0527	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper SDB-6	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	0.0731	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-6	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	1,335.8216	1,335.8216	1,335.8216	1,335.8216	1,335.8216	1,335.8216	1,335.8216	1,335.8216	1,335.8216	1,335.8216	1,335.8216	1,335.8216	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	0.6000	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 375,594	$ 362,537	$ 350,130	$ 328,303	$ 385,272	$ 467,511	$ 506,811	$ 516,230	$ 432,822	$ 363,316	$ 361,692	$ 386,442	$ **4,836,660**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,148,313	2,073,631	2,002,664	1,877,823	2,203,674	2,674,058	2,898,847	2,952,722	2,475,650	2,078,089	2,068,801	2,210,362	**27,664,634**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	16,548,672	15,973,389	15,426,728	14,465,062	16,975,125	20,521,291	22,246,368	22,659,816	18,998,660	15,947,697	15,876,413	16,962,784	**212,602,004**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	226,705	197,648	211,335	191,769	232,547	273,083	305,907	311,592	252,821	219,295	211,272	233,253	**2,867,228**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	240,155	214,066	220,824	208,683	217,221	239,586	263,480	265,246	225,297	226,050	213,940	242,434	**2,776,983**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	150,007	133,710	137,932	130,349	135,682	149,651	164,576	165,679	140,726	141,196	133,632	151,430	**1,734,570**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	38,716	33,754	36,091	32,750	39,714	46,637	52,242	53,213	43,176	37,451	36,081	39,835	**489,659**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	466,512	415,832	428,961	405,377	421,962	465,406	511,822	515,252	437,649	439,112	415,588	470,939	**5,394,413**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	89,360	79,652	82,167	77,650	80,827	89,148	98,039	98,696	83,831	84,112	79,606	90,208	**1,033,296**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	7,723,720	7,455,220	7,200,078	6,751,242	7,922,758	9,613,908	10,422,080	10,615,774	8,900,579	7,471,250	7,437,855	7,946,803	**99,461,267**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	1,971,120	1,756,984	1,812,458	1,712,809	1,782,885	1,966,446	2,162,566	2,177,055	1,849,166	1,855,350	1,755,953	1,989,825	**22,792,617**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 29,386,286**	**$ 28,169,185**	**$ 27,364,150**	**$ 25,668,040**	**$ 29,857,164**	**$ 35,907,533**	**$ 38,972,635**	**$ 39,666,114**	**$ 33,277,721**	**$ 28,304,244**	**$ 28,061,558**	**$ 30,125,333**	**$ 374,759,962**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**594,589**	**529,238**	**547,220**	**515,776**	**542,502**	**601,191**	**662,104**	**667,161**	**564,657**	**560,675**	**531,274**	**600,982**	**6,917,368**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 29,980,874**	**$ 28,698,423**	**$ 27,911,370**	**$ 26,183,816**	**$ 30,399,666**	**$ 36,508,724**	**$ 39,634,739**	**$ 40,333,274**	**$ 33,842,378**	**$ 28,864,919**	**$ 28,592,832**	**$ 30,726,315**	**$ 381,677,330**

Consumers Energy Company

2016 Transmission and Energy Market Administration Expenses

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper SDB-1	5,780	5,646	5,448	5,119	6,072	7,338	7,925	8,037	6,801	5,640	5,598	5,971	**75,375**
2	Hours per Month	Day in Month * 24	744	696	744	720	744	720	744	744	720	744	720	744	**8,784**
3	Delivered MWhs	Workpaper SDB-3	3,370,485	3,100,789	3,074,079	2,928,537	3,043,355	3,352,528	3,677,269	3,702,165	3,152,424	3,154,670	2,989,317	3,381,092	**38,926,710**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	367.4323	367.4323	367.4323	367.4323	367.4323	367.4323	367.4323	367.4323	367.4323	367.4323	367.4323	367.4323	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	2,856.7517	2,856.7517	2,856.7517	2,856.7517	2,856.7517	2,845.8341	2,845.8341	2,845.8341	2,845.8341	2,845.8341	2,845.8341	2,845.8341	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-6	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper SDB-6	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-6	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	1,304.7985	1,304.7985	1,304.7985	1,304.7985	1,304.7985	1,304.7985	1,304.7985	1,304.7985	1,304.7985	1,304.7985	1,304.7985	1,304.7985	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	0.9469	0.9469	0.9469	0.9469	0.9469	0.9469	0.9469	0.9469	0.9469	0.9469	0.9469	0.9469	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 375,464	$ 366,759	$ 353,897	$ 332,526	$ 394,432	$ 476,670	$ 514,801	$ 522,076	$ 441,787	$ 366,369	$ 363,641	$ 387,871	$ **4,896,292**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,123,759	2,074,523	2,001,771	1,880,886	2,231,049	2,696,218	2,911,901	2,953,054	2,498,907	2,072,318	2,056,886	2,193,938	**27,695,211**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	16,512,025	16,129,220	15,563,583	14,623,712	17,346,196	20,882,731	22,553,235	22,871,969	19,354,518	16,050,504	15,930,979	16,992,476	**214,811,150**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	229,207	209,449	216,042	196,447	240,786	281,603	314,267	318,709	260,995	223,655	214,829	236,781	**2,942,770**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	259,527	238,761	236,704	225,497	234,338	258,145	283,150	285,067	242,737	242,910	230,177	260,344	**2,997,357**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	153,896	141,582	140,362	133,717	138,960	153,076	167,904	169,041	143,940	144,042	136,492	154,381	**1,777,394**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	43,003	39,296	40,533	36,857	45,176	52,834	58,962	59,795	48,967	41,962	40,306	44,424	**552,114**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	471,868	434,110	430,371	409,995	426,070	469,354	514,818	518,303	441,339	441,654	418,504	473,353	**5,449,739**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	91,677	84,341	83,615	79,656	82,779	91,189	100,022	100,699	85,746	85,807	81,309	91,966	**1,058,807**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	7,541,735	7,366,892	7,108,542	6,679,263	7,922,736	9,574,611	10,340,528	10,486,665	8,873,934	7,359,063	7,304,262	7,790,952	**98,349,183**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	3,191,537	2,936,160	2,910,868	2,773,053	2,881,776	3,174,534	3,482,033	3,505,608	2,985,054	2,987,181	2,830,607	3,201,581	**36,859,992**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 30,389,150**	**$ 29,465,346**	**$ 28,533,770**	**$ 26,847,102**	**$ 31,392,273**	**$ 37,499,588**	**$ 40,569,820**	**$ 41,114,188**	**$ 34,803,871**	**$ 29,448,043**	**$ 29,069,873**	**$ 31,220,323**	**$ 390,353,348**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**606,548**	**557,748**	**554,519**	**526,508**	**554,025**	**613,376**	**673,801**	**678,797**	**576,052**	**569,422**	**540,119**	**609,743**	**7,060,660**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 30,995,699**	**$ 30,023,094**	**$ 29,088,289**	**$ 27,373,610**	**$ 31,946,298**	**$ 38,112,964**	**$ 41,243,621**	**$ 41,792,985**	**$ 35,379,924**	**$ 30,017,465**	**$ 29,609,993**	**$ 31,830,066**	**$ 397,414,008**

Consumers Energy Company

2017 Transmission and Energy Market Administration Expenses

Case No.: 2013 PSCR Plan Case
Witness: SDBurgdorf
Exhibit: A-1 (SDB-1)
Page: 5 of 5
Date: September 2012

Line	Description	Source / Calculation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Billing Determinants														
1	Peak MWs	Workpaper SDB-1	5,843	5,674	5,509	5,176	6,175	7,415	8,003	8,079	6,874	5,704	5,656	6,025	**76,133**
2	Hours per Month	Day in Month * 24	744	672	744	720	744	720	744	744	720	744	720	744	**8,760**
3	Delivered MWhs	Workpaper SDB-3	3,406,158	3,044,025	3,134,964	2,955,518	3,070,031	3,381,387	3,704,752	3,731,053	3,179,220	3,169,545	3,005,100	3,398,807	**39,180,560**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper SDB-6	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	$ 64.9591	
5	Schedule 2 - Reactive Support	Workpaper SDB-4	364.0383	364.0383	364.0383	364.0383	364.0383	364.0383	364.0383	364.0383	364.0383	364.0383	364.0383	364.0383	
6	Schedule 9 - Network Transmission Service	Workpaper SDB-5	3,034.5182	3,034.5182	3,034.5182	3,034.5182	3,034.5182	3,024.1517	3,024.1517	3,024.1517	3,024.1517	3,024.1517	3,024.1517	3,024.1517	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper SDB-6	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	0.0533	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper SDB-6	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	0.0770	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper SDB-6	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	0.0457	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper SDB-6	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper SDB-6	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	
12	Schedule 24 - Balancing Area Cost Adder - Energy Markets	Workpaper SDB-6	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	
13	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Workpaper SDB-5a	1,273.0470	1,273.0470	1,273.0470	1,273.0470	1,273.0470	1,273.0470	1,273.0470	1,273.0470	1,273.0470	1,273.0470	1,273.0470	1,273.0470	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper SDB-5a	1.0792	1.0792	1.0792	1.0792	1.0792	1.0792	1.0792	1.0792	1.0792	1.0792	1.0792	1.0792	
	Expenses														
15	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 379,556	$ 368,578	$ 357,860	$ 336,228	$ 401,122	$ 481,672	$ 519,868	$ 524,805	$ 446,529	$ 370,527	$ 367,409	$ 391,379	$ **4,945,531**
16	Schedule 2 - Reactive Support	Line 1 * Line 5	2,127,076	2,065,554	2,005,487	1,884,262	2,247,937	2,699,344	2,913,399	2,941,066	2,502,400	2,076,475	2,059,001	2,193,331	**27,715,331**
17	Schedule 9 - Network Transmission Service	Line 1 * Line 6	17,730,690	17,217,856	16,717,161	15,706,666	18,738,150	22,424,085	24,202,286	24,432,121	20,788,019	17,249,761	17,104,602	18,220,514	**230,531,910**
18	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	231,705	203,229	218,460	198,634	244,871	284,558	317,361	320,374	263,797	226,193	217,055	238,923	**2,965,160**
19	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	262,274	234,390	241,392	227,575	236,392	260,367	285,266	287,291	244,800	244,055	231,393	261,708	**3,016,903**
20	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	155,525	138,990	143,142	134,949	140,178	154,394	169,159	170,360	145,163	144,721	137,213	155,190	**1,788,984**
21	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	43,472	38,129	40,987	37,267	45,942	53,388	59,542	60,108	49,493	42,438	40,723	44,826	**556,315**
22	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	476,862	426,164	438,895	413,773	429,804	473,394	518,665	522,347	445,091	443,736	420,714	475,833	**5,485,278**
23	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	92,647	82,797	85,271	80,390	83,505	91,974	100,769	101,485	86,475	86,212	81,739	92,448	**1,065,711**
24	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	7,438,414	7,223,269	7,013,216	6,589,291	7,861,065	9,439,643	10,188,195	10,284,947	8,750,925	7,261,460	7,200,354	7,670,108	**96,920,887**
25	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	3,675,880	3,285,071	3,383,211	3,189,555	3,313,136	3,649,147	3,998,119	4,026,502	3,430,972	3,420,530	3,243,064	3,667,947	**42,283,134**
26	METC Agency Agreement		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
27	Total Transmission Expenses	**Lines 15-20 + 24-26**	**$ 32,003,120**	**$ 30,738,936**	**$ 30,081,930**	**$ 28,269,161**	**$ 33,184,851**	**$ 39,395,211**	**$ 42,595,652**	**$ 42,989,466**	**$ 36,574,603**	**$ 30,995,723**	**$ 30,562,089**	**$ 32,801,099**	**$ 410,191,840**
28	Total Energy Market Administration Expenses	**Lines 21-23**	**612,982**	**547,090**	**565,153**	**531,430**	**559,251**	**618,756**	**678,977**	**683,940**	**581,058**	**572,386**	**543,176**	**613,107**	**7,107,305**
29	**Total Transmission and Energy Markets Administration Expenses**	**Lines 27 + 28**	**$ 32,616,102**	**$ 31,286,027**	**$ 30,647,083**	**$ 28,800,591**	**$ 33,744,102**	**$ 40,013,967**	**$ 43,274,628**	**$ 43,673,406**	**$ 37,155,662**	**$ 31,568,108**	**$ 31,105,265**	**$ 33,414,205**	**$ 417,299,145**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

DIRECT TESTIMONY

OF

NATALIE N. BUSACK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2012

Q. Please state your name and business address.

A. Natalie N. Busack, 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 I in the Revenue Section of the Rates Department.

Q. Please describe your educational background and business experience.

A. I graduated in December 2003 from Michigan State University with a Bachelor of Arts in General Management and a Bachelor of Science in Psychology. In addition, I have attended courses on utility ratemaking.

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

A. I joined Consumers Energy in April 2002.

Q. Since joining Consumers Energy, what positions have you held?

A. I joined Consumers Energy as a part time Customer Service Representative while I completed my degrees at Michigan State. In December of 2003 I was promoted to a Financial Analyst for the Customer Services Department. In January 2006, I moved to Rate Administration where I was responsible for developing, implementing, and administering Company tariffs in addition to implementing rate orders and performing research on regulatory issues. In April 2012, I moved to my current position in the Revenue Requirements section of the Rates Department where I am now responsible for forecasting the monthly power supply cost recovery ("PSCR") factor and preparation of economic studies relating to the operations of the Company's business units.

Q. Have you previously testified or sponsored testimony in any regulatory proceedings?

A. Yes, I sponsored testimony in Case No. U-15943, the Company's reconciliation of the 2008 and 2009 Electric Choice Incentive Mechanism and U-16759, the Company's previous Residual Balance filing.

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

A. The purpose of my testimony is to present the calculation of the 2013 PSCR factor.

Q. Are you sponsoring any exhibits in connection with your testimony?

A. Yes, I am sponsoring the following exhibit:

Exhibit A-2 (NNB-1) Calculation of 2013 PSCR Factor.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. Please summarize Exhibit A-2 (NNB-1).

A. Exhibit A-2 (NNB-1) shows the calculation of the 2013 PSCR factor including: (i) total power supply costs provided by Ms. Walz; (ii) transmission expenses provided by Mr. Burghoff; (iii) Schedule 2 Reactive Revenue provided by Mr. Burghoff; and (iv) NO_x allowance expenses, urea costs, and aqueous ammonia costs provided by Mr. Kehoe.

Q. Please describe in more detail the calculations in Exhibit A-2 (NNB-1).

A. The 2013 PSCR factor is calculated by first summing the total system power supply costs on Line 1, the net transmission expenses on Line 4, the total of NO_x allowance costs, urea costs, and aqueous ammonia costs ("Total Environmental Costs") shown on Line 8 and the projected 2012 underrecovery on Line 9. That sum, shown on Line 10, is divided by total system energy requirements (measured in units of kilowatthours or kWh) on Line 11, provided to me by Company witness Warriner, to determine the average cost per kWh of requirements on Line 12. From this quotient is subtracted the base recovery factor (shown on Line 13) collected through the standard tariffs as approved by the Commission. This remaining expense per kWh amount ($0.00179 set forth on Line 14) is multiplied by the Line and Transformation Loss Factor on Line 15 to determine the 2013 per kWh PSCR factor of $0.00194 at sales, shown on Line 16.

Q. Please describe the 2012 underrecovery shown on Line 9 of Exhibit A-2 (NNB-1).

A. In its December 21, 2006, order in MPSC Case No. U-15001, the Commission authorized Consumers Energy to include prior years' underrecoveries (and overrecoveries) in the current year's PSCR plan. *See*, December 21, 2006, order at Page 9, Ordering Paragraph. The basis of the 2012 underrecovery on Line 9 is the Company's booked year-to-date August actual underrecovery and the sum of the projected PSCR recoveries for each month remaining in 2012, including interest. The Company projects that by the end of the 2012 plan year, the total principal underrecovery will be $25,377,708. Including interest, the projected underrecovery is $23,886,422.

Q. Is there a difference between the PSCR factor calculated in this proceeding and the actual PSCR factor charged throughout the year?

A. Yes. The factor calculated in this proceeding sets the maximum factor that the Company is authorized to charge throughout the year. The actual PSCR factor can be at or below this maximum factor. The actual PSCR factor is determined each month based on the Company's latest forecast of sales and PSCR costs and available actual sales and PSCR cost information. Each month, using this information, the Company attempts to implement future monthly PSCR factors that will result in an annual zero over- or under-recovery.

Q. What is the purpose of this policy?

A. The Company's policy is intended to match costs with the customers who cause the Company to incur those costs. While it is unlikely that the Company will succeed in exactly matching costs with customers who incurred the costs, the monthly calculations described above attempt to minimize any over- and under-recovery for the PSCR year. Any amounts over collected are subject to refund with interest at the Company's authorized return on equity, which is currently 10.30%.

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 Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

EXHIBIT

OF

NATALIE N. BUSACK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2012

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Calculation of 2013 PSCR Factor

Line				
1	System Power Supply Costs[1]		$	1,659,682,000
	System Transmission Expenses			
2	Total Transmission Expenses[2]	$ 321,184,422		
3	Less: Schedule 2 Reactive Revenue[3]	(19,706,000)		
4	Net Transmission Expenses		$	301,478,422
	Environmental Costs			
5	NOx Allowance Costs[4]	$ 252		
6	Urea Costs[5]	3,813,000		
7	Aqueous Amonia[6]	2,229,000		
8	Total Environmental Costs		$	6,042,252
9	2012 Underrecovery[7]		$	23,886,422
10	Total System Power Supply Costs		$	1,991,089,095
11	Total System Requirements in kWh[8]			36,697,085,000
	Jurisdictional Factor Calculation			
12	Average Cost at Requirements (Line 10 / Line 11)		$	0.05425
13	Less: Base Recovery Factor[9]		$	0.05246
14	Remaining Cost per kWh (Line 12 - Line 13)		$	0.00179
15	Line & Transformation Loss Factor[10]			1.086
16	2013 PSCR Factor at Sales (Line 14 x Line 15)		$	0.00194

Sources:
[1]Exhibit A-15 (STW-1), Page 1, Line 26
[2] Exhibit A-1 (SDB-1), line 29
[3]SDBurgdorf Testimony, Page 8, Line 1
[4]Exhibit A-10 (DBK-3), Line 22
[5]Exhibit A-11 (DBK-4), Line 3
[6]Exhibit A-12 (DBK-5), Line 3
[7]NNB Workpaper NNB 1
[8]Exhibit A-21 (LDW-4), page 3, Line 13
[9]Per Order in Case No. U-16794
[10]Per Rule C-8 of the Company Tariffs

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

DIRECT TESTIMONY

OF

JIM K. CHILSON II, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

Q. Would you please state your name and business address?

A. Jim K. Chilson II, 1945 Parnall Rd, Jackson, Michigan.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Fuels Transportation & Planning Director in the Energy Supply Operations Department.

Q. Would you please describe your educational background and business experience?

A. I graduated in 1991 with a Bachelor of Science in Engineering from Oakland University and in 1993 with a Master of Science in Electrical Engineering from Michigan State University. I have been employed by Consumers Energy since 1993. I have held a variety of engineering, operating and supervisory positions. In 2011, I joined the Fossil Fuel Supply Division as the Fuels Transportation and Planning Director in the Energy Supply Operations Department.

Q. What are your duties as the Fuels Transportation & Planning Director?

A. My duties include:

- the preparation of short and long term projections specifying purchase volumes and pricing for coal, oil, and natural gas as fuel for generation;
- the optimization of the distribution of coal to the generating plants to minimize the delivered cost of coal;
- managing plant fuel inventories and the daily logistics for the delivery of fuel to the generating plants;
- supervising the management and maintenance of the leased rail cars for coal delivery;
- managing the projection of volumes and prices of #6 fuel oil for Karn 3&4, natural gas

for Zeeland and Karn 3&4, and #2 fuel oil and natural gas for the combustion turbines;

- supervising the purchase of natural gas for the Cobb, Zeeland and Karn 3&4 Plants;
- preparation of testimony and filings for presentation before the MPSC.

General Background

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

A. I am sponsoring testimony with respect to the Company's projected costs of coal, oil and natural gas used for electric generation.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, I am sponsoring the following exhibits that were prepared by me or under my supervision:

Exhibit A-3 (JKC-1), Coal Contract & Annual Purchase Data

Exhibit A-4 (JKC-2), Estimated As-Burned Coal Costs – 2013

Exhibit A-5 (JKC-3), Estimated As-Burned Oil & Gas Costs – 2013

Exhibit A-6 (JKC-4), Estimated As-Burned Coal Costs (2014-2017)

Exhibit A-7 (JKC-5), Estimated As-Burned Oil & Gas Costs (2014-2017)

Coal Costs

Q. What actions has the Company taken to minimize its cost of coal and ensure adequate supply to meet customer demand?

A. The Fuel Supply Department endeavors to secure coal supplies in quantity and quality sufficient to meet the needs of the Company's coal fired generating units in an economical manner. Coals from different regions are evaluated and purchased based on total delivered blended cost. Long-term contracts are made with coal suppliers and transportation providers to ensure a secure supply of fuel at the most economical value offered. Long term contracts are competitively bid and to the extent possible, structured to allow volume flexibility in response to changes in market conditions. Short-term and annual coal contracts are also competitively bid. Railcars are leased to lower freight costs and audits are periodically performed on coal supply and freight invoices to ensure correctness. These are some of the actions taken by the Company to minimize the cost of coal.

Q. Can you elaborate on Consumers Energy's coal purchasing strategy?

A. Yes. Consumers Energy layers its coal purchases in such a way that each year it has a portfolio of coal purchase contracts. The portfolio for a given year will consist of contracts of various quality, with various volumes, term lengths, and prices. Although these purchases are competitively bid, the pricing of these contracts is reflective of the market at the time the purchase was made. Some contracts within the portfolio may be above or below the market at the time of delivery depending on how the market has changed relative to the time the purchase was made. Maintaining such a portfolio minimizes price risk to Consumers Energy's customers and protects them from price volatility in the market. In addition to providing stability in pricing, procuring coal supplies in such a portfolio also mitigates supply risk to our customers in the event coal supplies become constrained. Consumers Energy purchases and secures quantities over time that typically enables the Company to have approximately 70% to 90% of its anticipated total volume secured by the fall of each year for the following calendar year; approximately 40% to 50% secured for the next calendar year, and approximately 20% to 25% secured for the third calendar year.

Q. Have there been any changes to your coal purchase strategy for 2013.

A. No. The Company is continuing to layer coal purchases in order to maintain a diverse portfolio of contracts, however the purchases will be biased to the lower end of the aforementioned ranges. Low natural gas prices in the present market have resulted in natural gas generation plants being more competitive with coal generation plants. Natural gas prices have started to increase recently and forecasts for 2013 indicate that natural gas prices will continue to increase. In the near term, coal and natural gas prices are such that a small increase or decrease in the price of one commodity could have a large impact on the need for the other commodity. Due to this price sensitivity, which creates commodity volume uncertainty, the Company is allowing more open position for 2013 delivery than it might have in previous years.

<u>Environmental Considerations</u>

Q. Would you briefly explain the air pollution considerations that have an impact on the Company's coal supply purchasing program?

A. During 2013, the State of Michigan Natural Resources and Environmental Protection Act 451 requires the use of fuel with a maximum of 1.67 pounds of sulfur dioxide (SO_2) per million Btu heat input to meet the sulfur dioxide emission limit at the JCWeadock and DEKarn plants at Essexville, the BCCobb Plant at Muskegon, the JRWhiting Plant at Erie, and the JHCampbell Plant Units 1&2 at West Olive. The federal Environmental Protection Agency ("EPA") has established 1.2 pounds SO_2 per million Btu heat input as the maximum sulfur dioxide emission limit for JHCampbell Unit 3. Also, Act 451 has stipulated that the Company must keep stack emission opacity levels at all plants below 20%. These restrictions dictate the quality of coal purchased to meet system requirements.

Additionally, under the EPA's Acid Rain Program and the State's NOx Budget Trading Program, emissions of SO_2 and NOx are monitored to account for transferable emission allowances.. These emission allowances have an economic value, and to the extent various fuel alternatives affect the value of emission allowances that are required to be surrendered, such value also is considered in the Company's coal supply purchasing program.

<u>Coal Purchase Contracts</u>

Q. How many annual and multi-year contracts will Consumers Energy have during 2013?

A. Presently the Company has nine multiyear long-term and annual coal purchase contracts that will be in effect during 2013. Eight of these purchase contracts provide for the western coal supply to our coal plants (the JHCampbell Complex, the BCCobb Plant, the DEKarn 1-2 Plant, the JCWeadock Plant, and the JRWhiting Plant) and the remaining one purchase contract provides for the eastern coal supply for these same plants.

Q. Does Exhibit A-3 (JKC-1) list these contracts?

A. Yes, it does.

Q. Briefly describe the data contained in Exhibit A-3 (JKC-1).

A. Exhibit A-3 (JKC-1) contains information on the current multi-year long-term and annual contracts expected to be in effect during the calendar year 2013. Column "a" lists the suppliers which for the purpose of this exhibit are represented by contract number. Column "b" identifies the coal type, that is, whether it is eastern coal (originating typically in the Central Appalachian regions of Kentucky and West Virginia) or western coal (originating typically in the Powder River Basin region in Wyoming and Montana). Columns "c" and "d" identify the starting and ending dates for the contract, respectively.

Column “e” identifies the contract volumes we currently expect to nominate for 2013.

Q. Could you briefly explain “nominate”?

A. Some of our coal contracts offer the Company the ability to specify, or “nominate,” a purchase volume on a six-month or annual basis, within a contract specified minimum and maximum tonnage. This ability to “nominate” tonnage provides the Company with some flexibility to respond to demand and market conditions by taking more or less tonnage from a given contract depending upon the anticipated coal requirements and depending on the contract’s price compared to the projected price of coal that may be available for purchase during the nomination period.

Q. Do you anticipate entering into any additional multi-year or annual coal supply contracts from which tonnage would be received in 2013?

A. Yes. We anticipate soliciting for additional western coal before the end of 2012.

<u>Coal Contract Determination</u>

Q. Please describe how coal prices were projected for 2013?

A. Each of Consumers Energy’s current coal contracts specify fixed pricing for the coal being purchased under the contract. The remaining open position was estimated based on the current market projection for that period.

<u>Coal Transportation Contracts</u>

Q. What arrangements does the Company have for the transportation of coal that is purchased?

A. Coal is transported by rail from the mines either directly to generating plants or to lake terminal facilities, where the coal is transferred to lake vessels for delivery to the generating plants. During 2013, the Company expects to have in effect five contracts that will provide for the shipment of coal on railroads and, one contract that will provide vessel services and two that will provide terminal services for shipments of coal out of Chicago. These contracts were entered into as a result of a competitive bidding process, with the lowest cost provider being selected.

Coal Transportation Rate Determination

Q. What procedure was used to determine freight rates?

A. Freights rates were adjusted either by fixed contract pricing or according to the performance of indices to which the rates are tied. In addition, fuel surcharges, where provided for in the transportation contracts or as defined in railroad published tariffs, have been included.

Coal Tonnage Determination

Q. In general, how were the coal tonnages determined for 2013?

A. As described in witness Walz's testimony, a computer model is used to determine production estimates (*i.e.*, MWh production and hence MMBtu coal burn requirements to support that production) for each generating unit. The model uses a variety of inputs, but those most closely related to fuel volume determination include fuel mix, coal quality and generating unit efficiency. Using the MMBtu coal burn requirements determined from the model, along with inventory considerations, monthly purchase volumes of coal are determined for each plant. A comparison of these purchase requirements with the amount of coal available under contract determines the need for spot coal purchases.

Q. How many tons has the Company purchased under contract for delivery in 2013 and do you expect to purchase more?

A. The Company presently has approximately 4.9 million tons of coal committed for 2013 from the multi-year or annual purchases shown in Exhibit A-3 (JKC-1). At this time, the Company anticipates it will purchase additional coal in 2012 for 2013 delivery. However, the volume of coal for this purchase is yet to be determined.

Spot Coal Purchases

Q. What volumes do you expect to purchase on a spot basis during 2013?

A. Approximately 2 to 3 million tons are expected to be purchased on a spot basis.

Q. Briefly describe the considerations in estimating spot prices for 2013.

A. Spot market prices for coal are generally consistent with current market conditions and fluctuate with supply and demand, economic conditions, environmental compliance requirements, coal mining industry capacity and permitting issues, alternative fuel prices, strikes, and other factors. Recent low natural gas prices have reduced the demand for coal resulting in lowered spot prices than in previous years. Spot prices are expected to remain relatively low in 2013. In the longer term, it is expected that the demand for coal, at least western coal, will recover and remain strong due to its lower sulfur content compared to eastern coal. The global market for coal has not as yet appeared to significantly impact the price of western coal as compared to eastern coal, due in large part to its lower quality and transportation issues impacting its exportability into the global market.

No new purchases for eastern coal are expected in 2013. The Company has already secured sufficient eastern coal to meet the expected demand in 2013 and, therefore, no spot purchases of eastern coal are anticipated at this time.

Types of Coal

Q. What types of coal does Consumers Energy expect to utilize in 2013?

A. The Company burns a variety of coals in varying combinations at its generating plants in an effort to minimize its production costs and meet regulatory requirements. A blend of low-sulfur eastern and low-sulfur western coal is included in the fuel mix.

Q. How much western coal has been included in this projection?

A. On a system-wide basis, we expect to burn approximately 8.4 million tons of western coal or approximately 97% by weight of our total coal burn requirements in 2013.

Q. How much eastern coal has been included in this projection?

A. The Company presently has a single eastern coal contract in effect for 2013 with a contract volume of 264,000 tons. Because of the anticipated low cost of gas in 2013, eastern coal is only projected to be used during periods of high electrical demand when eastern coal is necessary to achieve full capability from the coal generation fleet. The Company believes it has purchased enough eastern coal to ensure an adequate supply for the estimated high demand days. At this time, no additional purchases are planned for 2013.

As-Burned Coal Costs

Q. How were the as-burned coal costs developed?

A. The as-burned cost of coal is determined based on the cost of coal in inventory multiplied by the amount of coal projected to be burned during a particular period. Specifically, for each plant inventory location, the total monthly delivered cost of coal for the current month is added to the cost in inventory at the end of the previous month and divided by the delivered coal volume for the current month plus the volume in inventory at the end of the previous month. This average cost of fuel in inventory is then multiplied by the current month burn volume to arrive at the as-burned cost for the current month. The current month's ending inventory is then calculated by subtracting the current month burn cost and volume, respectively, from the starting inventory values for the current month, plus any purchase cost and volume. It is important to note that although the coal cost for this case are developed based on the as-burn, the generation units are dispatched based on the replacement cost of fuel. Once coal is purchased, it becomes a fixed expense for economic dispatch purposes. The variable expense relating to coal consists of spot coal that will be purchased at the next opportunity to replace coal that is consumed from inventory. Coal units are dispatched at this spot coal price so their production at this price can be compared to the current market.

Q. What is included in the total monthly delivered cost of coal?

A. The total monthly delivered cost of coal to each generating plant is determined based on the cost of any contract and spot coal purchases allocated to the plant; the application of any necessary or required freeze protection treatments to insure all lading can be removed from the railcars during winter months and to insure compliance with railroad operating rules and tariffs; the application of any necessary or required dust inhibitors to insure compliance with railroad operating rules and tariffs; any harbor maintenance fees; as well as the cost of transporting the coal to the plant.

Q. What is shown on Exhibit A-4 (JKC-2)?

A. Exhibit A-4 (JKC-2) summarizes the projected as-burned costs and tonnage at each of the Company’s coal-fired generating plants for the year 2013. The total cost includes primary fuel, auxiliary fuel, freeze protection and dust inhibiting treatments, and the projected state air emission fees.

2014 – 2017 Projection of Coal Costs

Q. How were the coal prices determined to obtain the coal cost projections for the years 2014-2017?

A. In a manner similar to 2013, existing supply and transportation contracts were adjusted separately, based on the expected performance of the adjustment indices to which the contracts are tied. Those contracts that have fixed prices had the fixed prices input with no escalation. Forecasted coal prices and transportation costs were utilized for open tonnage positions.

Q. Where do the coal cost projections appear?

A. These costs are shown in Exhibit A-6 (JKC-4).

Q. Are any new contracts anticipated for the 2014-2017 time period?

A. Yes. We will be entering into new supply and transportation contracts to replace those that expire. The pricing for any new supply and transportation contracts are modeled as described earlier in this testimony.

Oil and Natural Gas Cost Projections

Q. To which generating plants do your oil and natural gas projections apply?

A. I am supplying the oil and gas fuel cost projections for Consumers Energy's oil and gas fired generating units, those being the Zeeland plant, the DEKarn 3&4 plant, the BCCobb plant, and all of the combustion turbine units.

Q. What types of fuel do these units burn?

A. The Zeeland plant burns natural gas, as well as the BCCobb Plant for start-up and over-firing. DEKarn 3&4 can burn natural gas, No. 6 fuel oil (both low and mid-sulfur), or a combination thereof. The combustion turbines burn either natural gas or No. 2 fuel oil.

Q. Holding the discussion for the Zeeland plant until later, what sources were assumed for each of these fuels?

A. The No. 6 oil burned at Karn 3&4 will be purchased on a spot basis. A portion of the gas for Karn 3&4 will be purchased on a spot basis, and the remainder under third party contract, but with spot pricing terms. Gas for the Cobb Plant and the combustion turbine at the Karn/Weadock complex will be purchased on a spot basis. Any No. 2 fuel oil for the combustion turbines will also be purchased on a spot basis. Any gas used for any of the remaining combustion turbines will come from the Consumers Energy Company natural gas utility or the Michigan Consolidated Gas Company (MichCon) pursuant to the Michigan Public Service Commission (MPSC) approved tariff rates (Consumers Energy Rate GS-3 and MichCon Rate GS-2).

Q. Could you briefly explain why much of the oil and natural gas that is purchased for consumption in the generating units is purchased on a spot basis, rather than under contract like it is for coal?

A. Much of the reason for doing so lies with the difficulty in accurately predicting the demand for these generally higher cost units. Unlike the coal units, which are typically lower in cost, earlier units to dispatch, and whose production is generally more predictable, the oil and gas units typically have more expensive variable costs, and as a result are among the last units to be dispatched. The utilization of these units depends on a number of difficult-to-predict factors, including but not limited to unit availability, competing market power price and availability, weather and its effects on system electric load, electric transmission constraints, and the more volatile nature of the oil and gas markets. In addition to the unpredictable nature of their use, there is also an issue with the limited amount of storage available for either oil or gas, and the situation that may arise should volumes be contracted for, required to be taken, and not consumed. For these reasons, the Company has not believed it prudent to purchase significant volumes of oil or gas ahead of time under long-term contract

Q. In the absence of long term contracts, what does Consumers Energy do to mitigate some of the price volatility of its oil and natural gas purchases for electric generation?

A. The ability of the Karn 3&4 units to burn either oil or gas or a blend of the two, offers us the ability to operationally hedge the price of either fuel against the other. Unlike gas, which because of storage limitations is generally purchased on a spot basis near the time it is consumed, oil is purchased over a period of months to minimize the cost of oil in inventory and within inventory constraints. Additionally, oil is purchased in varying qualities and prices and blended in the storage tanks at the plant to provide additional gas and oil blending flexibility. For example, low sulfur oil is available on site to enable the units to run entirely on oil without blending with gas. Lower cost mid-sulfur oil is also available in storage to blend with a typical mixture of approximately 30% natural gas. The mid-sulfur oil, when mixed in varying degrees with low sulfur oil, accommodates the ability to burn any mixture of oil and gas. Finally, the units may also burn 100% gas, though not at full capacity.

Q. What steps has the Company taken to minimize its natural gas related costs, including storage, for its generating units?

A. The Company utilizes the provisions contained in its gas transportation agreements to minimize its natural gas related costs. This includes monitoring gas usage and market prices during the month and employing strategies to minimize cost and to insure that month end gas balances are within the specified contract tolerances. It also includes utilizing its available storage (in the form of the contract Authorized Tolerance Level) with the Consumers Energy gas utility and MichCon to purchase lower cost gas during periods of lower gas demand and store such gas ahead of the anticipated usage.

Q. To what extent is the storage available on the Consumers Energy gas utility system utilized for the electric utility?

A. As described in the response to the previous question, the available storage provided for in the gas transportation agreement with the gas utility is utilized to store gas purchased when prices are lower. We have not seen it prudent to purchase additional storage, over and above that amount provided for in our gas transportation agreement for several reasons. These reasons include but are not limited to: (1) the difficulty in accurately predicting the production on these units and the concern that additional storage be purchased and not used; (2) recognition of the potential impacts to the Consumers Energy gas customers if storage were used by the electric utility to benefit its electric customers, from both a supply and cost standpoint; (3) any gas storage purchased by the electric utility from the gas utility would be provided pursuant to tariffs and would only be available to the Karn 3&4 plant for a portion of its needs on a seasonal basis, and; (4) as stated previously for Karn 3&4, we have the ability to maintain an oil inventory that can be used to operationally hedge the cost of gas against the cost of oil, which reduces the need to store gas.

<u>Zeeland Plant Natural Gas</u>

Q. What is the source of fuel for the Zeeland plant?

A. The Zeeland plant is a natural gas fired facility that is connected to the ANR pipeline system through a lateral pipeline owned and operated by SEMCO Energy Gas Company ("SEMCO").

Q. What has Consumers Energy done to assure a reliable and economic supply of fuel for the Zeeland facility?

A. Consumers Energy has entered into a contract with a third party (which was competitively bid, and with the lowest bidder being selected) to act as a gas management service agent ("Agent") on behalf of the Company with regard to the gas supply for Zeeland. The gas management service agent's obligations under the contract include purchasing the gas, transporting the gas from its purchase origin to the point of delivery (the SEMCO interconnection), and storing gas when necessary. Entering into an agreement such as this allows the Company to take advantage of the gas management service agent's diversity of gas purchasing/transportation contracts, gas purchasing experience, as well as the portfolio of arrangements the Agent has with ANR and other pipelines in North America. This experience and expertise enables the gas management service agent to provide firm transportation and storage to the Company more economically than if the Company were required to obtain firm transportation and storage directly from ANR and other pipeline companies. In addition to the firm transportation provided for under this service contract, the Company also has a contract with SEMCO that was assigned to the Company at the time of the Zeeland plant purchase, which provides firm gas transportation from SEMCO's point of interconnection with the ANR pipeline system to the Zeeland plant.

Q. How does the gas management services contract work?

A. Procuring gas supply for the Zeeland plant is a difficult process involving numerous complex steps. In addition to procuring the gas commodity and transportation service, the gas management service agent is responsible for providing gas pricing information to the Company which is relied upon by the Company to bid energy from the Zeeland plant into the MISO energy market. The Agent is then responsible for purchasing gas as directed by Consumers Energy in the Day-ahead gas market. The Agent also purchases gas as directed by Consumers Energy in the Intra-day and Real-time gas markets as the MISO accepts offers from Zeeland in the MISO energy market. These purchases of gas on behalf of Consumers Energy are conducted on a day ahead, intraday and real-time basis and gas is stored on an as-needed basis to balance against dispatch requests from MISO. The pricing of the gas management services contract is based on published indices depending on the time of the year (either the Chicago city gate or the Michcon city gate). Gas storage above a specified tolerance amount incurs an additional cost.

Q. Does the Company pay the Agent a separate amount to transport the gas from the point of origin to the ANR-SEMCO interconnection point?

A. No. The amount paid to the Agent is an all-inclusive price which includes the price of the commodity and, all transportation services from the point of origin to the ANR-SEMCO interconnection.

Q. Do you foresee any changes in the Company's use of the agent in 2013 to provide gas for the Zeeland Plant?

A. Yes. The Company's contract with the agent expires in May, 2013. In this PSCR plan case, however, the Company assumes the cost to supply gas to the Zeeland plant will be provided at a cost similar to that provided by third party agent.

Q. Does the Company pay SEMCO for the use of the lateral pipeline it owns that connects the Zeeland Plant to the gas supply provided by the Agent to the ANR-SEMCO interconnection point?

A. Yes. The Company pays a fixed annual demand charge as provided for in the contract it assumed from the previous owner of the Zeeland plant, at the time the Zeeland plant was acquired by the Company, for firm transportation of up to 186,000 Mcf of gas per day.

Q. Have you developed fuel cost projections for the Company's oil-fired and natural gas-fired generating units for the year 2013?

A. Yes. These fuel cost projections are shown in Exhibit A-5 (JKC-3).

Q. On what were these fuel cost estimates based?

A. These fuel cost estimates are based on price information assembled by the Corporate Risk Management Department within Consumers Energy and are indicative of the future market prices for oil and gas at the time the price deck was prepared.

Q. What were your underlying assumptions for your cost projections for 2013?

A. The price of No. 6 Oil and No. 2 Oil are based on crude oil projections provided by the Corporate Risk Management Department and our projection of the relationship between crude oil and No. 6 oil and No. 2 oil. The price of gas for Karn 3&4 and the Weadock combustion turbine is based on the market gas prices (NYMEX Henry Hub) provided by the Corporate Risk Management Department added to the cost of firm transport provided through the DCP Midstream Partners Bay Area Pipeline or with interruptible transport provided through the Consumers Energy gas distribution system. The price of gas for the Zeeland plant is based on gas market prices (monthly NYMEX Henry Hub) provided by the Corporate Risk Management Department adjusted to the gas indices (either the

Michcon or Chicago city gate) associated with the pricing of the gas to Consumers Energy by the agent as defined within the gas management services contract. Also added into the burn cost projection for Zeeland is the demand charge associated with the use of the SEMCO lateral pipeline. The price of gas for the Cobb Plant is also based on the market gas projections provided by the Risk Management Department, but with seasonally firm transportation provided through the MichCon system. Gas prices for the combustion turbines are based on the applicable standard tariff charges for the type of service involved. Gas for the Straits and Gaylord combustion turbines is provided pursuant to MichCon's Rate No. GS-2 and gas service for the Morrow and Thetford units is provided pursuant to Consumers Energy Company's Gas Rate GS-3.

Q. Why does the Company use the NYMEX Henry Hub price as the basis for its gas price projections rather than futures prices for the Michcon city gate or the Chicago city gate?

A. The NYMEX Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange and is generally accepted to be the primary gas price set for the North American natural gas market. There or no similar pricing points projected for the Michcon or Chicago city gates.

Q. How does the Company determine its projection for the Michcon and Chicago city gates?

A. The Company has determined historical relationships between the Michcon and Chicago city gates compared to the NYMEX Henry Hub based on actual trades at all three points. These relationships are then used to adjust the projected NYMEX Henry Hub price to arrive at an unbiased projection for the Michcon and Chicago city gate locations.

Q. What actions has the Company taken to minimize the cost of oil and gas identified in your exhibit?

A. The Zeeland gas management services agreement was competitively bid with the lowest bidder selected. Regarding the other oil and gas burning units, spot purchases of gas and oil are made through a competitive bidding process, selecting the lowest bidder. Specific to No. 6 oil, the Company optimizes its purchases considering supply availability, price, and inventory considerations. Also, to the extent it is available; DEKarn 3&4 also burns low cost on-spec waste oil. More fundamentally, the Company's generating units are dispatched on an economic basis, thereby minimizing the use of the generally higher priced oil and gas-fired peaking generation.

Q. Have you developed oil and natural gas cost projections for the years 2014 through 2017?

A. Yes, the annual costs are shown in Exhibit A-7 (JKC-5).

Q. How were your oil and natural gas projections determined for the years 2014 through 2017?

A. The methods used to determine these costs are the same as used to determine the costs for 2013.

Q. Does this complete your prepared direct 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 Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

EXHIBITS

OF

JIM K. CHILSON, II

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Coal Contract & Annual Purchase Data

Line	(a) Supplier Contract No	(b) Coal Type	(c) Contract Start Date	(d) Contract End Date	(e) 2013 Volume (Tons)
1	100	Western	1/1/2011	12/31/2013	781,945
2	101	Western	1/1/2011	12/31/2013	258,570
3	102	Western	1/1/2011	12/31/2013	300,000
4	110	Western	1/1/2011	12/31/2013	711,360
5	121	Western	1/1/2012	12/31/2014	1,123,200
6	125	Western	1/1/2012	12/31/2014	533,520
7	134	Western	1/1/2013	12/31/2013	374,400
8	137	Western	1/1/2013	12/31/2015	561,600
9	122	Eastern	1/1/2012	12/31/2014	264,000
10				**Total**	**4,908,595**

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17133
Exhibit: A-4 (JKC-2)
Witness: JKChilson
Date: September 2012

Estimated As-Burned Coal Costs - 2013

Line	(a) Plant	(b)	(c) Burn Volume (Tons)	(d) Burn Dollars
1	JHCampbell 1-2		1,637,771	$ 86,693,866
2	JHCampbell 3 (CE Owned)		2,570,416	$ 130,914,377
3	BCCobb 4-5		812,558	$ 45,969,774
4	DEKarn 1-2		1,682,440	$ 86,638,198
5	JCWeadock 7-8		926,097	$ 48,649,368
6	JRWhiting 1-3		862,508	$ 47,047,635
			8,491,790	$ 445,913,218
7		Total Primary Fuel		$ 445,913,218
8		Total Auxilliary Fuel		$ 8,105,083
9		Total Freeze/Dust Treatment		$ 1,388,885
10		State Air Emission Fees		$ 752,254
11		Total Coal Cost		$ 456,159,440

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17133
Exhibit: A-5 (JKC-3)
Witness: JKChilson
Date: September 2012
Page: 1 of 1

Estimated As-Burned Oil & Gas Costs - 2013

Line	(a) Plant	(b)	(c) Burn Volume (BBLS/MCF)	(d) Burn Dollars
1	Zeeland Generating Station		23,227,168	$ 86,421,319
2	DEKarn 3-4 - Oil		0	$ 0
3	DEKarn 3-4 - Gas		1,543,826	$ 10,207,972
4	BCCobb 1-3		-	$ -
5	Combustion Turbines - Oil		-	$ -
6	Combustion Turbines - Gas		-	$ 503,940
				$ 97,133,231
7		Total Primary Fuel		$ 97,133,231
8		Total Auxilliary Fuel		$ 7,564,582
9		State Air Emission Fees		$ 62,020
10		Total Oil & Gas Cost		$ 104,759,833

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17133
Exhibit: A-6 (JKC-4)
Witness: JKChilson
Date: September 2012
Page: 1 of 1

Estimated As-Burned Coal Costs
2014 - 2017

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (Tons)					
	Plant		2014	2015	2016	2017
1	JHCampbell 1-2		1,898,591	1,926,817	1,897,661	1,822,138
2	JHCampbell 3 (CE Owned)		2,995,196	2,533,957	2,627,112	3,082,091
3	BCCobb 4-5		988,606	280,042	-	-
4	DEKarn 1-2		1,223,700	1,916,148	1,788,230	1,760,835
5	JCWeadock 7-8		1,058,721	290,259	-	-
6	JRWhiting 1-3		1,164,819	330,689	-	-
7		Total Burn Tonnage	9,329,634	7,277,911	6,313,003	6,665,064
	Burn Dollars					
	Plant		2014	2015	2016	2017
8	JHCampbell 1-2		$ 95,178,427	$ 95,541,958	$ 98,106,228	$ 97,874,911
9	JHCampbell 3 (CE Owned)		$ 143,449,574	$ 125,011,926	$ 135,232,631	$ 164,706,636
10	BCCobb 4-5		$ 54,579,569	$ 15,201,977	$ -	$ -
11	DEKarn 1-2		$ 60,392,438	$ 92,453,903	$ 90,807,999	$ 90,906,822
12	JCWeadock 7-8		$ 51,873,207	$ 13,816,319	$ -	$ -
13	JRWhiting 1-3		$ 60,964,056	$ 16,486,446	$ -	$ -
14		Total Primary Fuel	$ 466,437,271	$ 358,512,529	$ 324,146,859	$ 353,488,368
15		Total Primary Fuel	$ 466,437,271	$ 358,512,529	$ 324,146,859	$ 353,488,368
16		Total Auxilliary Fuel	$ 8,556,064	$ 6,481,893	$ 5,137,425	$ 5,208,902
17		Total Freeze/Dust Treatment	$ 1,535,914	$ 1,161,021	$ 1,074,271	$ 1,134,132
18		State Air Emission Fees	$ 763,538	$ 774,991	$ 786,616	$ 798,415
19		Total Coal Burn Cost	$ 477,292,787	$ 366,930,434	$ 331,145,171	$ 360,629,818

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17133
Exhibit: A-7 (JKC-5)
Witness: JKChilson
Date: September 2012
Page: 1 of 1

Estimated As-Burned Oil & Gas Costs
2014 - 2017

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (BBLS/MCF)					
	Plant		2014	2015	2016	2017
1	Zeeland Generating Station		16,273,476	21,711,495	21,660,542	19,412,849
2	DEKarn 3-4 - Oil		1,015	4,945	6,356	1,160
3	DEKarn 3-4 - Gas		1,750,086	1,671,959	1,632,449	1,658,329
4	BCCobb 1-3		-	-	-	-
5	Combustion Turbines - Oil		-	-	-	-
6	Combustion Turbines - Gas		1,233	410	3,083	1,015
7						
	Burn Dollars					
	Plant		2014	2015	2016	2017
8	Zeeland Generating Station		$ 67,729,093	$ 95,032,825	$ 99,361,964	$ 94,613,128
9	DEKarn 3-4 - Oil		$ 64,262	$ 302,128	$ 379,253	$ 68,341
10	DEKarn 3-4 - Gas		$ 11,812,547	$ 11,858,254	$ 12,029,887	$ 12,554,166
11	BCCobb 1-3		$ -	$ -	$ -	$ -
12	Combustion Turbines - Oil		$ -	$ 1	$ 2	$ 4
13	Combustion Turbines - Gas		$ 511,864	$ 506,472	$ 523,654	$ 510,694
14		Total Primary Fuel	$ 80,117,767	$ 107,699,680	$ 112,294,760	$ 107,746,334
15		Total Primary Fuel	$ 80,117,767	$ 107,699,680	$ 112,294,760	$ 107,746,334
16		Total Auxilliary Fuel	$ 6,219,064	$ 8,459,307	$ 8,835,092	$ 8,856,642
18		State Air Emission Fees	$ 62,950	$ 63,894	$ 64,853	$ 65,825
19		Total Oil & Gas Burn Cost	$ 86,399,782	$ 116,222,882	$ 121,194,705	$ 116,668,802

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

DIRECT TESTIMONY

OF

DAVID B. KEHOE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2012

Q. Please state your name and business address.

A. David B. Kehoe, 1945 W. Parnall Road, 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 Director of Staff, Electric Generation.

Q. Please describe your educational background.

A. I received a Bachelor of Science (Chemistry) degree in December 1977 from the University of Michigan. I also received a Master's degree (Business Administration) in May 1982 from the University of Detroit.

Q. Please describe your business experience.

A. In 1978 I began working as an Associate Engineer for The Detroit Edison Company ("Detroit Edison"). In this capacity I worked at Detroit Edison's Engineering Research Department largely serving as an analytical chemist specializing in instrumental analytical chemistry. From mid 1982 to September 1989 I held the position of Fuels Engineer, and was responsible for both the operation of Detroit Edison's fuels laboratory as well as for consulting with the operating power plants on fuel and combustion product impacts. Additionally, from 1985 until 1989 I was in charge of the Polychlorinated Biphenyls ("PCB") analysis laboratory. This laboratory analyzed soil and oil samples for the presence of PCBs and was part of Detroit Edison's program to remove PCBs from existing equipment and to verify the absence of PCBs from soil samples that came from remediation of transformer-oil spills. While at Detroit Edison, I was also a member of the American Chemical Society, the ASTM Committee on Corrosion and Deposits from Combustion Gasses, and ASTM D-5 Committee.

In 1998 I left the position of Senior Engineer at Detroit Edison and went to CQ Inc., a subsidiary of the Electric Power Research Institute. While at CQ Inc., I held the position of Project Manager, and consulted with utilities, coal companies, and engineering firms on fuel selection and fuel impacts. Additionally, I served on the Department of Energy coal research project peer review panel.

In 1998, I left CQ Inc. and joined CMS Generation, a subsidiary of CMS Energy, as a Plant Support Manager. My responsibilities included negotiation of long-term service agreements, power purchase agreements, operation and maintenance agreements for new and existing power plants, providing operations review and cost estimates in development of new power plants, and providing technical assistance to existing power generating assets. In 2000, I became the Asset Manager for the Jorf Lasfar Energy Company in Morocco, and was responsible for representing CMS Energy's interests in that project. In that capacity I also served on the Management Committee of Jorf Lasfar, which functions as that project's board of directors. As such, I was responsible for dividend declarations, cash management policy, setting annual goals and objectives, reviewing performance and establishing salary bonus structure for the project management. In addition, I also served in a similar capacity for the GasAtacama project in northern Chile. In April of 2004, I accepted the position of Director of Staff, Electric Generation.

Q. What are your responsibilities as Director of Staff, Electric Generation?

A. As Director of Staff, Electric Generation, I am responsible for strategic planning for the electric generation business of Consumers Energy. This function includes air quality and regulatory oversight as well as financial planning and budgeting.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I sponsored testimony in the following cases: Case Nos. U-13917 and U-13917-R (2004 PSCR Plan and Reconciliation cases); Case Nos. U-14274 and U-14274-R (2005 PSCR Plan and Reconciliation cases); Case Nos. U-14701 and U-14701-R (2006 PSCR Plan and Reconciliation cases); Case No. U-14347 (2006 Electric Rate case); Case Nos. U-15001 and U-15001-R (2007 PSCR Plan and Reconciliation cases); Case Nos. U-15415 and U-15415-R (2008 PSCR Plan and Reconciliation cases); Case No. U-15245 (2008 Electric Rate case); Case Nos. U-15675 and U-15675-R (2009 PSCR Plan and Reconciliation case); Case No. U-15645 (2009 Electric Rate case); Case No. U-16113 (2009 Show Cause Order); Case No. U-16054 (2009 Depreciation Practices for Electric and Common Utility Plant); Case No. U-16055 (2009 Depreciation Practices for Ludington Pumped Storage Plant); Case No. U-16045 and U-16045-R (2010 PSCR Plan and Reconciliation cases); Case No. U-16191 (2010 Electric Rate case); Case No. U-16432 and U-16432-R (2011 PSCR Plan and Reconciliation cases); Case No. U-16536 (2011 Depreciation Practices for Lake Winds Energy Park); Case No. U-16794 (2011 Electric Rate case); Case No. U-16890 (2012 PSCR Plan case) and Case No. U-17087 (2013 Electric Rate case).

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

A. The purpose of my testimony is to: 1) identify and explain the major fossil and Ludington plant outages that are planned for this period; 2) identify and support Consumers Energy's periodic outage plans and random outage rate ("ROR") projections for the 2013 PSCR plan year; 3) compare the projected ROR for fossil, hydro, Ludington and peaker units with actual ROR experienced in the five-year period 2007-2011; 4) address availability of generating units for the five-year forecast period; 5) identify forecasted air emissions allowances for the 2013 PSCR plan year, as well as the period 2014 through 2017; 6) identify forecasted urea expenses for the 2013 PSCR plan year, as well as the period 2014 through 2017; and 7) identify forecasted aqueous ammonia expenses for the 2013 PSCR plan year, as well as the period 2014 through 2017, and request this expense be included in all future PSCR Plan cases.

Q. Are you sponsoring exhibits with your testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-8 (DBK-1)	Major Outages in the 2013 PSCR Plan.
Exhibit A-9 (DBK-2)	2013 PSCR Random Outage Rate Projections.
Exhibit A-10 (DBK-3)	2013-2017 NO_x Allowance Budget.
Exhibit A-11 (DBK-4)	2013-2017 Urea Expenses.
Exhibit A-12 (DBK-5)	2013-2017 Aqueous Ammonia Expenses.

Major Generating Plant Outages for 2013

Q. Please define major generating plant outages.

A. Major generating plant outages are defined as outages that last 28 days or more. These outages generally deal with major pieces of equipment that require disassembly and repair and/or replacement.

Q. Please describe the outages that have been reflected by Company witness Walz in the dispatch of the Company's generating plants in this case.

A. Exhibit A-8 (DBK-1) describes those outages.

Q. Please describe the major activities, planned start dates and durations for each of the outages listed on Exhibit A-8 (DBK-1).

A. I describe the individual outages in the following testimony.

<u>Ludington 2</u>

The outage at Ludington 2 is scheduled to begin January 7, 2013, and is projected to last for 35 days. The outage is for cavitation repairs, penstock inspection, and testing.

<u>Campbell 2</u>

The outage at Campbell 2 is scheduled to begin February 16, 2013, and is projected to last for 72 days. The outage will be to inspect and repair the induced draft ("ID") fans, the Selective Catalytic Reduction ("SCR") unit, the Economizer and re-heater. During this outage, the Pulse Jet Fabric Filers and Activated Carbon Injection ("ACI") systems will be connected. The Company will also replace the deaerator and deaerator ("DA") tank.

<u>Karn 4</u>

The outage at Karn 4 is scheduled to begin March 30, 2013, and is projected to last for 46 days. The outage is for boiler and cooling tower repairs.

<u>Whiting 3</u>

The outage at Whiting 3 is scheduled to begin April 13, 2013, and is projected to last for 35 days. The outage is to replace the precipitator field.

<u>Zeeland CC</u>

The outage at Zeeland CC is scheduled to begin April 13, 2013, and is projected to last for 28 days. The outage is to inspect and maintain the hot gas path and steam turbine.

Karn 3

The outage at Karn 3 is scheduled to begin September 5, 2013, and is projected to last for 74 days. The outage is for cooling tower repairs.

Ludington 3

The outage at Ludington 3 is scheduled to begin September 8, 2013, and is projected to last for 35 days. The outage is for cavitation repairs, penstock inspection and testing and shaft packing.

Ludington 4

The outage at Ludington 4 is scheduled to begin September 8, 2013, and is projected to last for 238 days. This will be the first unit outage of Ludington's multi-year $800 million overhaul and upgrade. The outage is for the replacement and upgrade of all major components - water turbine (aka – runner), wicket gates, generator/pump, and stator.

Miscellaneous Outages

Q. Are there other outages projected for 2013?

A. Yes. There are planned outages scheduled for various generating plants that are all shorter than 28 days. These outages are scheduled to remove screens from valves after turbine inspections, to remove zebra mussels from raw water piping, to chemically clean boiler tube internals, or to perform work on precipitators or other equipment that will not operate for extended periods without attention. All of these planned outages have been scheduled for periods that avoid high replacement power expenses.

Mothballed Generating Units

Q. Please define what is meant by mothballing generating units.

A. Mothballing refers to removing the generating unit from operations for the present, but maintaining the unit in a physical state such that it can become operational at a future date when market conditions are more conducive to their operation.

Q. Please provide an update on the generating units that Consumers Energy has mothballed.

A. Cobb Units 1-3 were "mothballed" in 2009 and are expected to continue in that status. Consumers Energy will continue to evaluate the economics and timing of returning these units to service.

Q. Does Consumers Energy have additional generating units in a mothball status?

A. Yes. Consumers Energy received approval from Midwest Independent Transmission System Operator ("Midwest ISO") to mothball the following Combustion Turbine Units ("CTs") effective October 14, 2010:

- Thetford 1, 2, 5, 6 & 7
- Weadock A
- Whiting A

Q. Did Consumers Energy seek approval to mothball additional units?

A. Yes. In August 2011, Consumers Energy filed a request with Midwest ISO to mothball the following CTs:

- Campbell A
- Gaylord 1-4
- Morrow A & B
- Thetford 3, 4, 8 & 9
- Straits

Q. Did Midwest ISO approve Consumers Energy's August 2011 request?

A. Midwest ISO approved Consumers Energy's request to mothball Morrow A & B and Campbell A effective February 15, 2012. Thetford 3, 4, 8 & 9 were approved for mothball status effective May 14, 2012. Midwest ISO rejected the Company's request to mothball Gaylord 1-4 and Straits. The Company is currently in negotiations with Midwest ISO, to determine how the needs of all parties can be met and anticipates an agreement to be reached sometime in late 2012.

Q. Did Consumers Energy file a request with Midwest ISO to mothball the seven smallest coal-fired units – Cobb 4 & 5, Weadock 7 & 8 and Whiting 1-3?

A. Yes. The Company filed three (3) applications with Midwest ISO (one for each site – Cobb, Weadock and Whiting) in February 2012.

Q. What is the status of these applications?

A. At the writing of this testimony, Midwest ISO has not responded to the Company's applications to mothball the seven units.

ROR Projections

Q. How are the ROR projections for the fossil, hydro and peaker units in this case developed?

A. The ROR projections in this case are developed using a five-year average (2007-2011) and are modified to reflect current operating conditions. This is shown in my Exhibit A-9 (DBK-2). Significant exceptions to the five-year average are described below.

Campbell 2

The 2013 ROR is projected to be 6.24% higher than the five-year average. Random outage rates typically increase prior to scheduled maintenance, which in this case is scheduled in the fall of 2014.

Karn 1

The 2013 ROR is projected to be 18.43% lower than the five-year average. In 2008 and into 2009, this unit experienced a turbine failure due to a cracked rotor that has now been repaired.

Cobb 4

The 2013 ROR is projected to be 5.24% higher than the five-year average. This unit is one of seven that will be mothballed in 2015 due to increasingly stringent emissions standards. Because these units are not expected to operate beyond 2015, spending has been reduced, increasing ROR projections.

Availability

Q. Do you provide projections for availability of the generating units?

A. Yes. The 2013 projected availability for each of the generating units is also shown in column b of Exhibit A-9 (DBK-2).

Q. Do you have an availability projection for the five-year, 2013-2017 forecast period?

A. Yes. The Company is projecting the overall availability of all the generating units will average about 85% over the five-year forecast period.

Nitrogen Oxides (“NO_x”) Allowances

Q. Please describe how the Company proposes to recover NO_x allowance expenses.

A. The Company requested and received approval in MPSC Case No. U-13917 to recover NO_x allowance expenses as PSCR expenses. I recommend the same treatment for the recovery of NO_x emission expense in 2013.

Q. Do you have an exhibit related to NO_x emission allowance expense?

A. Yes. Exhibit A-10 (DBK-3).

Q. Please describe Exhibit A-10 (DBK-3).

A. Exhibit A-10 (DBK-3) is the Company’s projection of NO_x emission allowance expense for the PSCR Plan year 2013 and the remainder of the five-year forecast years, 2014 through 2017. The exhibit presents an annual tabulation of the allowance inventory, forecasted emissions, and a summary of the projected allowances that will be surrendered to the U.S. Environmental Protection Agency (“EPA”) for compliance under the Clean Air Interstate Rule (“CAIR”).

Q. Please provide background on the status of CAIR.

A. CAIR was finalized in March 2005 and governs the emission of sulfur dioxide (“SO_2”) and NO_x from fossil fueled electric generating units through the use of an allowance based “cap and trade” program. In this program, one NO_x allowance permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. The program regulates NO_x for both the ozone season (May through September) and on an annual basis. Phase I reductions began in 2009 for NO_x and in 2010 for SO_2. Phase II reductions are scheduled to begin in 2015 for both NO_x and SO_2.

In July 2008 CAIR was vacated by the DC Circuit Court, but in a second ruling in December 2008 the DC Circuit Court reinstated the regulation and remanded it back to the EPA to be revised. In August 2011 the EPA finalized the CAIR replacement rule, known as the Cross-State Air Pollution Rule ("CSAPR"). Phase I of CSAPR was scheduled to take effect on January 1, 2012, and Phase II on January 1, 2014. However, on December 30, 2011, the US Court of Appeals for the District of Columbia stayed the rule pending judicial review. In a final ruling on August 21, 2012, the Court vacated the rule in its entirety and ordered that the "EPA must continue administering CAIR pending the promulgation of a valid replacement." The Company is currently complying with CAIR and anticipates that rule will remain in effect for at least the next few years.

Q. How has Consumers Energy calculated the cost of the allowances set forth on Exhibit A-10 (DBK-3)?

A. Consumers Energy has calculated the "average cost" of each of the NO_x allowances inventory in accordance with 18 CFR 101, Uniform System of Accounts for Public Utilities and Licensees Subject to the Provisions of The Federal Power Act. Using the "average cost" methodology, allowances allocated to the Company by the EPA at zero cost are averaged with the cost of allowances that were exchanged and purchased. Banked allowances from the previous year are carried forward into the current inventory at the average cost of the previous year's inventory account. Forecasted purchases are based on a forecasted allowance market price. Allowances are expensed at the average cost of the inventory account, regardless of the actual cost of the individual allowance.

Q. Are these NO_x emission allowance expenses reflected elsewhere in this filing?

A. Yes, they are reflected in the overall PSCR factor calculated by Company witness Natalie N. Busack.

SO_2 Allowances

Q. Does Consumers Energy expect to incur any expenses or revenues in 2013 related to the SO_2 allowance program?

A. No, Consumers Energy does not expect to incur SO_2 expenses or revenues in 2013. However, future SO_2 expenses are possible.

Urea Expenses

Q. Are there additional PSCR expenses for which you are seeking recovery in 2013?

A. Yes, Exhibit A-11 (DBK-4) identifies the projected Urea Based Ammonia System ("UBAS") expenses through 2017.

Q. Please describe Exhibit A-11 (DBK-4).

A. In 2013, Consumers Energy projects spending $3.81 million for urea. In 2014, Consumers Energy expects to spend $4.23 million for urea. In 2015 through 2017, expenses are expected to be $3.75, $3.77, and $4.14 million, respectively.

Q. What is urea, and what does Consumers Energy use it for?

A. Urea is a solid chemical that is converted into ammonia. The ammonia reacts with NO_x in the SCR and reduces the amount of NO_x emissions and the need to purchase NO_x allowances.

Q. Has the Commission previously approved the inclusion of urea in the Company's PSCR?

A. Yes. The Company requested and received approval to recover urea expenses as a PSCR expense in MPSC Case No. U-15415. I recommend the same treatment in 2013.

Aqueous Ammonia Expenses

Q. Are there additional PSCR expenses for which you are seeking recovery in 2013?

A. Yes, Exhibit A-12 (DBK-5) identifies the projected aqueous ammonia expenses through 2017.

Q. Please describe Exhibit A-12 (DBK-5).

A. In 2013, Consumers Energy projects spending $2.23 million for aqueous ammonia at Karn 1 & 2. In 2014, Consumers Energy expects to spend $1.50 million for aqueous ammonia. In 2015 through 2017, expenses are expected to be $2.28, $2.13, and $2.16 million, respectively.

Q. How will aqueous ammonia be used?

A. Aqueous ammonia performs the same function as urea, reducing the amount of NO_x emissions and the need to purchase NO_x allowances. In 2012, the Company replaced the UBAS at Karn 1 & 2 with aqueous ammonia. This new system was designed to be more reliable and effective at reducing NO_x emissions.

Q. Has the Commission previously approved the inclusion of aqueous ammonia?

A. No. The Company requested recovery of aqueous ammonia expenses in U-16890 (2012 PSCR Plan case), however the Commission has not yet filed their order. Consumers Energy is seeking the Commission's approval to include this expense in this and all future PSCR plan cases as aqueous ammonia performs the same function as urea and urea expenses have been approved by the Commission.

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 Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

EXHIBITS

OF

DAVID B. KEHOE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17133
Exhibit: A-8 (DBK-1)
Witness: DBKehoe
Date: September 2012
Page: Page 1 of 1

MAJOR OUTAGES IN THE 2013 PSCR PLAN

Line	Unit	Days in 2011	Start Date	Stop Date
	(a)	(b)	(c)	(d)
1	Ludington 2	35	01/07/13	02/11/13
2	JH Campbell 2	72	02/16/13	04/29/13
3	DE Karn 4	46	03/30/13	05/15/13
4	JR Whiting 3	35	04/13/13	05/18/13
5	Zeeland CC	28	04/13/13	05/11/13
6	DE Karn 3	74	09/05/13	11/18/13
7	Ludington 3	35	09/08/13	10/13/13
8	Ludington 4	238	09/08/13	05/04/14

2013 PSCR Random Outage Rate Projections

Line	Plant (a)	Availability (b)	Periodic Factor (c)	2013 Projected ROR (d)	Actual ROR 2007-2011 (e)
1	Campbell 1	90.66%	2.47%	7.05%	8.35%
2	Campbell 2	68.58%	22.46%	11.55%	5.31%
3	Campbell 3	84.52%	7.26%	8.86%	4.81%
4	Cobb 4	84.07%	2.21%	14.03%	8.79%
5	Cobb 5	83.80%	6.63%	10.25%	9.25%
6	Karn 1	90.53%	0.00%	9.47%	27.90%
7	Karn 2	91.85%	0.00%	8.15%	13.39%
8	Karn 3	74.46%	20.27%	6.60%	12.23%
9	Karn 4	80.94%	12.60%	7.39%	6.64%
10	Weadock 7	78.46%	12.35%	10.49%	12.12%
11	Weadock 8	79.30%	12.35%	9.53%	11.86%
12	Whiting 1	86.65%	5.52%	8.28%	12.03%
13	Whiting 2	87.07%	1.10%	11.96%	8.87%
14	Whiting 3	81.28%	10.83%	8.85%	8.13%
15	Ludington 1	95.61%	2.34%	2.10%	0.92%
16	Ludington 2	84.63%	13.55%	2.10%	3.28%
17	Ludington 3	87.64%	10.48%	2.10%	4.09%
18	Ludington 4	66.40%	32.17%	2.10%	1.33%
19	Ludington 5	93.93%	4.05%	2.10%	1.27%
20	Ludington 6	93.33%	4.67%	2.10%	5.73%
21	CTs[1]	85.00%	0.00%	15.00%	12.43%
22	Hydros	92.84%	5.56%	1.70%	1.90%
23	Zeeland CC	85.70%	10.26%	4.50%	3.75%[2]
24	Zeeland 1A	95.72%	1.82%	2.50%	2.73%[2]
25	Zeeland 1B	88.47%	9.26%	2.50%	2.56%[2]

[1]Does not include the Zeeland CTs.
[2]2008-2011 ROR

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17133
Exhibit A-10 (DBK-3)
Witness: DBKehoe
Date: September 2012

2013-2017 NO_X ALLOWANCE BUDGET

Line No.	2013 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
1	Beginning Bank from 2012	2,689	$0.19	$504.07
2	2013 Inventory	7,444	$0.00	$0.00
3	Forecasted Purchases	0	$137.03	$0.00
4	**Total**	**10,133**	**$0.05**	**$504.07**
5	Forecasted Emissions	5,061		
6	Banked Allowances Surrendered	-2,689	$0.05	$133.75
7	2013 Inventory Surrendered	-2,372	$0.05	$118.01
8	Forecasted Purchases Surrendered	0	$0.05	$0.00
9	**Ending Balance**	**5,072**	**$0.05**	
10	**Total Expense**			**$251.76**

Line No.	2013 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
11	Beginning Bank from 2012	5,485	$0.00	$0.00
12	2013 inventory	16,280	$0.00	$0.00
13	Forecasted Purchases	0	$138.77	$0.00
14	**Total**	**21,765**	**$0.00**	**$0.00**
15	Forecasted Emissions	11,405		
16	Banked Allowances Surrendered	-5,485	$0.00	$0.00
17	2013 Inventory Surrendered	-5,920	$0.00	$0.00
18	Forecasted Purchases Surrendered	0	$0.00	$0.00
19	**Ending Balance**	**10,360**	**$0.00**	
20	**Total Annual Season Expense**			**$0.00**

20	**Total Ozone Season Expense**		**$251.76**
21	**Total Annual Season Expense**	+	**$0.00**
22	**Total Expense for 2013**		**$251.76**

2013-2017 NOX ALLOWANCE BUDGET

Line No.	2014 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
23	Beginning Bank from 2013	5,072	$0.05	$252.31
24	2014 Inventory	7,444	$0.00	$0.00
25	Forecasted Purchases	0	$319.01	$0.00
26	**Total**	**12,516**	**$0.02**	**$252.31**
27	Forecasted Emissions	5,467		
28	Banked Allowances Surrendered	-5,072	$0.02	$102.24
29	2014 Inventory Surrendered	-396	$0.02	$7.97
30	Forecasted Purchases Surrendered	0	$0.02	$0.00
31	**Ending Balance**	**7,048**	**$0.02**	
32	**Total Ozone Season Expense**			**$110.21**

Line No.	2014 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
33	Beginning Bank from 2013	10,360	$0.00	$0.00
34	2014 Inventory	16,280	$0.00	$0.00
35	Forecasted Purchases	0	$330.60	$0.00
36	**Total**	**26,640**	**$0.00**	**$0.00**
37	Forecasted Emissions	12,871		
38	Banked Allowances Surrendered	-10,360	$0.00	$0.00
39	2014 Inventory Surrendered	-2,512	$0.00	$0.00
40	Forecasted Purchases Surrendered	0	$0.00	$0.00
41	**Ending Balance**	**13,768**	**$0.00**	
42	**Total Annual Season Expense**			**$0.00**

43	**Total Ozone Season Expense**		**$110.21**
44	**Total Annual Season Expense**	+	**$0.00**
45	**Total Expense for 2014**		**$110.21**

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17133
Exhibit A-10 (DBK-3)
Witness: DBKehoe
Date: September 2012

2013-2017 NOX ALLOWANCE BUDGET

Line No.	2015 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
46	Beginning Bank from 2014	0	$0.00	$0.00
47	Projected Allocation from the EPA	5,940	$0.00	$0.00
48	Forecasted Purchases	0	$350.00	$0.00
49	**Total**	**5,940**	**$0.00**	**$0.00**
50	Forecasted Emissions	2,186		
51	Banked Allowances Surrendered	0	$0.00	$0.00
52	2015 Inventory Surrendered	-2,186	$0.00	$0.00
53	Forecasted Purchases Surrendered	0	$0.00	$0.00
54	**Ending Balance**	**3,754**	**$0.00**	
55	**Total Ozone Season Expense**			**$0.00**

Line No.	2015 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
56	Beginning Bank from 2014	0	$0.00	$0.00
57	Projected Allocation from the EPA	15,955	$0.00	$0.00
58	Forecasted Purchases	0	$369.97	$0.00
59	**Total**	**15,955**	**$0.00**	**$0.00**
60	Forecasted Emissions	7,053		
61	Banked Allowances Surrendered	0	$0.00	$0.00
62	2015 Inventory Surrendered	-7,053	$0.00	$0.00
63	Forecasted Purchases Surrendered	0	$0.00	$0.00
64	**Ending Balance**	**8,902**	**$0.00**	
65	**Total Annual Season Expense**			**$0.00**

66	**Total Ozone Season Expense**		**$0.00**
67	**Total Annual Season Expense**	+	**$0.00**
68	**Total Expense for 2015**		**$0.00**

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No: U-17133
Exhibit A-10 (DBK-3)
Witness: DBKehoe
Date: September 2012

2013-2017 NOX ALLOWANCE BUDGET

Line No.	2016 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
69	Beginning Bank from 2015	3,754	$0.00	$0.00
70	Projected Allocation from the EPA	5,940	$0.00	$0.00
71	Forecasted Purchases	0	$350.00	$0.00
72	**Total**	**9,694**	**$0.00**	**$0.00**
73	Forecasted Emissions	2,198		
74	Banked Allowances Surrendered	-2,198	$0.00	$0.00
75	2016 Inventory Surrendered	0	$0.00	$0.00
76	Forecasted Purchases Surrendered	0	$0.00	$0.00
77	**Ending Balance**	**7,496**	**$0.00**	
78	**Total Ozone Season Expense**			**$0.00**

Line No.	2016 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
79	Beginning Bank from 2015	8,902	$0.00	$0.00
80	Projected Allocation from the EPA	15,955	$0.00	$0.00
81	Forecasted Purchases	0	$376.45	$0.00
82	**Total**	**24,857**	**$0.00**	**$0.00**
83	Forecasted Emissions	4,790		
84	Banked Allowances Surrendered	-4,790	$0.00	$0.00
85	2016 Inventory Surrendered	0	$0.00	$0.00
86	Forecasted Purchases Surrendered	0	$0.00	$0.00
87	**Ending Balance**	**20,067**	**$0.00**	
88	**Total Annual Season Expense**			**$0.00**

89	**Total Ozone Season Expense**		**$0.00**
90	**Total Annual Season Expense**	+	**$0.00**
91	**Total Expense for 2016**		**$0.00**

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

2013-2017 NOX ALLOWANCE BUDGET

Line No.	2017 Ozone Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
92	Beginning Bank from 2016	7,496	$0.00	$0.00
93	Projected Allocation from the EPA	5,940	$0.00	$0.00
94	Forecasted Purchases	0	$362.05	$0.00
95	**Total**	**13,436**	**$0.00**	**$0.00**
96	Forecasted Emissions	2,141		
97	Banked Allowances Surrendered	-2,141	$0.00	$0.00
98	2017 Inventory Surrendered	0	$0.00	$0.00
99	Forecasted Purchases Surrendered	0	$0.00	$0.00
100	**Ending Balance**	**11,295**	**$0.00**	
101	**Total Ozone Season Expense**			**$0.00**

Line No.	2017 Annual Season	Allowances	Average Cost $/Allowance	Inventory $
	(a)	(b)	(c)	(d)
102	Beginning Bank from 2016	20,067	$0.00	$0.00
103	Projected Allocation from the EPA	15,955	$0.00	$0.00
104	Forecasted Purchases	0	$395.76	$0.00
105	**Total**	**36,022**	**$0.00**	**$0.00**
106	Forecasted Emissions	4,987		
107	Banked Allowances Surrendered	-4,987	$0.00	$0.00
108	2017 Inventory Surrendered	0	$0.00	$0.00
109	Forecasted Purchases Surrendered	0	$0.00	$0.00
110	**Ending Balance**	**31,035**	**$0.00**	
111	**Total Annual Season Expense**			**$0.00**

112	**Total Ozone Season Expense**		**$0.00**
113	**Total Annual Season Expense**	+	**$0.00**
114	**Total Expense for 2017**		**$0.00**

Case No: U-17133
Exhibit: A-11 (DBK-4)
Witness: DBKehoe
September 2012

2013-2017 Urea Expense
(1,000's)

Line No.	Unit (a)	2013 (b)	2014 (c)	2015 (d)	2016 (e)	2017 (f)
1	**Campbell 2**	$1,112	$1,324	$1,397	$1,340	$1,211
2	**Campbell 3**	$2,701	$2,901	$2,354	$2,429	$2,924
3	**TTL**	$3,813	$4,225	$3,751	$3,769	$4,135

Case No: U-17133
Exhibit: A-12 (DBK-5)
Witness: DBKehoe
September 2012

2013-2017 Aqueous Ammonia Expense

(1,000's)

Line No.	Unit (a)	2013 (b)	2014 (c)	2015 (d)	2016 (e)	2017 (f)
1	**Karn 1**	$1,267	$792	$1,306	$1,154	$1,303
2	**Karn 2**	$962	$703	$976	$975	$859
3	**TTL**	$2,229	$1,495	$2,282	$2,129	$2,162

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

DIRECT TESTIMONY

OF

DAVID F. RONK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2012

Q. Please state your name and business address.

A. My name is David F. Ronk, Jr. and my business address is 1945 West Parnall Road, Jackson, Michigan.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director for Electric Transactions and Resource Planning.

QUALIFICATIONS

Q. Please describe your educational background and business experience.

A. I received the degree of Bachelor of Science in Engineering with a specialty in Civil Engineering from the University of Michigan in 1975. Since 1980 I have been a Registered Professional Engineer in the state of Michigan. I have practiced engineering while employed by Consumers Energy since January 1976 with assignments associated with: (i) the construction of Campbell Unit No. 3; (ii) construction of a wood-fired generating station proposed to be constructed in the early 1980s near Hersey, Michigan; (iii) construction of the Midland Nuclear Plant; (iv) assistance to attorneys defending the Company in litigation with the Dow Chemical Company; (v) development of what ultimately became known as the Midland Cogeneration Venture Limited Partnership; (vi) design and procurement of utility motor vehicles; (vii) operation of a fleet of rail cars used to haul coal; and (viii) development of the Company's Acid Rain Program compliance strategy and program. Since August 1997, I have been responsible for the development of strategies to manage the Company's exposure to financial risks associated with the operation of its generating units and the purchase of capacity and energy from others to serve the demand for electricity from Consumers Energy customers. Since 2007 I have also been responsible for the Company's resource planning activities.

Q. Have you testified in other cases?

A. Yes. I provided direct and rebuttal testimony in:

- MPSC Case No. U-10710-R (direct and rebuttal), the Company's 1995 Power Supply Cost Recovery ("PSCR") Reconciliation case, regarding the treatment of sulfur dioxide emission allowances;
- MPSC Case No. U-10973-R (direct), the Company's 1996 PSCR Reconciliation case;
- MPSC Case No. U-11180 (rebuttal), the Company's 1997 PSCR Plan case, regarding the treatment of sulfur dioxide emission allowances and certain permit conditions;
- MPSC Case No. U-12488 (direct and rebuttal), regarding certain terms and conditions of service for retail open access customers;
- MPSC Case No. U-13917 (direct, supplemental, and rebuttal), the Company's 2004 PSCR Plan case, regarding electric capacity requirements; the appropriate calculation of energy payment rates under certain qualified facility contracts, and the appropriate treatment of third party sales revenues in calculating PSCR costs;
- MPSC Case No. U-14031 (direct, rebuttal, and supplemental rebuttal), regarding the calculation of the hold harmless amount associated with the proposed resource conservation plan;

- MPSC Case No. U-14274 (direct and rebuttal), the Company's 2005 PSCR Plan case, regarding electric capacity requirements and costs for 2005;
- MPSC Case No. U-14347 (direct), regarding operating and maintenance expense and capital cost associated with electric and fuel supply for 2006 test year and power supply cost for the five-year period 2005 through 2009;
- MPSC Case No. U-13917-R (direct), the Company's 2004 PSCR Reconciliation case, regarding power supply costs incurred in 2004;
- MPSC Case No. U-14701 (direct, supplemental and rebuttal), the Company's 2006 PSCR Plan case, regarding electric capacity requirements and costs for 2006;
- MPSC Case No. U-14274-R (direct and supplemental), the Company's 2005 PSCR Reconciliation case, regarding power supply costs incurred in 2005;
- MPSC Case No. U-15001 (direct), the Company's 2007 PSCR Plan case, regarding electric capacity requirements and costs for 2007;
- MPSC Case No. U-15245 (direct and supplemental), regarding operating and maintenance expense and capital cost associated with electric and fuel supply for 2008 test year and power supply cost for the five-year period 2007 through 2011;

- MPSC Case No. U-14701-R (direct and supplemental), the Company's 2006 PSCR Reconciliation case, regarding power supply costs incurred in 2006;
- MPSC Case No. U-15290 (direct and supplemental), regarding the Company's balanced energy initiative;
- MPSC Case No. U-15415 (direct), the Company's 2008 PSCR Plan case, regarding electric capacity requirements and costs for 2008;
- MPSC Case No. U-15001-R (direct and supplemental), the Company's 2007 PSCR Reconciliation case, regarding power supply costs incurred in 2007;
- MPSC Case No. U-15645 (direct and rebuttal), regarding operating and maintenance expense and capital cost associated with electric and fuel supply for 2009 test year and power supply cost for the seven-year period 2007 through 2013;
- MPSC Case No. U-15675 (direct), regarding the Company's 2009 PSCR Plan, regarding electric capacity requirements and costs for 2009;
- MPSC Case No. U-15805/U-15889 (direct and rebuttal), regarding the 2009 renewable energy plan and energy optimization plan;
- MPSC Case No. U-15415R (direct and rebuttal), the Company's 2008 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2008;

- MPSC Case No. U-16045 (direct and rebuttal), the Company's 2010 PSCR Plan, regarding electric capacity requirements and costs for 2010;
- MPSC Case No. U-16191 (direct and rebuttal), regarding Operating and Maintenance expense and Capital cost associated with Electric and Fuel Supply for the test year ended June 30, 2011, and Power Supply Costs for the 12-month period ended June 30, 2011;
- MPSC Case No. U-15675R (direct, rebuttal, supplemental rebuttal, and second supplemental rebuttal), the Company's 2009 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2009;
- MPSC Case No. U-16300 (direct and rebuttal), the Company's 2009 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2009;
- MPSC Case No. U-16432 (direct and second rebuttal), the Company's 2011 PSCR Plan, regarding electric capacity requirements and costs for 2011;
- MPSC Case No. U-16543 (direct and rebuttal), the Company's application for approval of a Renewable Energy Plan amendment;
- MPSC Case No. U-16794 (direct), regarding Operating and Maintenance expense and Capital costs associated with Energy Supply Operations for the test year ended September 30, 2012;

- MPSC Case No. U-16045R (direct and rebuttal), the Company's 2010 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2010;
- MPSC Case No. U-16301 (direct), the Company's 2010 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2010;
- MPSC Case No. U-16890 (direct and supplemental), the Company's 2012 PSCR Plan, regarding electric capacity requirements and costs for 2012;
- MPSC Case No. U-16581 (direct), the Company's application for biennial review of its Renewable Energy Plan;
- MPSC Case No. U-16432R (direct), the Company's 2011 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2011;
- MPSC Case No. U-16655 (direct), the Company's 2011 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2011; and
- MPSC Case No. U-17087 (direct), regarding capacity planning matters associated with the test year beginning January 1, 2013, and subsequent periods.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony will address: (1) the selection of an appropriate capacity planning reserve margin target for 2013 through 2017; (2) the resources required to satisfy the capacity planning reserve margin target; (3) the resources previously approved by the

Commission; (4) the resources already purchased for the planning period; (5) the resources remaining to be purchased for the planning period; (6) I also discuss Midwest Independent Transmission System Operator's ("MISO") Capacity Market; (7) System Support Resources; (8) Black Start Resources; (9) Future plans for small combustion turbines; (10) Midwest Energy Market; (11) Renewable Resources Program; (12) Renewable Energy Plan; and (13) Energy Efficiency and Demand Management Program.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-13 (DFR-1)	Summer Peak Projected Planning Resource Credits, Demand and Margins;
Exhibit A-14 (DFR-2)	MISO Energy Market Settlement Charge Line Items.

CAPACITY PLANNING RESERVE MARGIN TARGET

Q. What is a Capacity Planning Reserve Margin Target?

A. The Capacity Planning Reserve Margin Target is the amount of capacity that a load serving entity (such as Consumers Energy) maintains to assure that sufficient capacity exists to provide adequate electric supply in each seasonal period. Generally, the Capacity Planning Reserve Margin Target is designed to include consideration of demand forecast variances, generator forced outages and derates, and transmission import limitations.

Q. How does the Company determine the Capacity Planning Reserve Margin target?

A. The Company relies on the MISO to determine the appropriate capacity planning reserve margin that Consumers Energy should maintain. For the 12-month period beginning on June 1, 2012, the MISO Loss of Load Expectation ("LOLE") Working Group performed a LOLE study which considered the probability that various amounts of generation resources would be adequate to serve firm demand in the MISO footprint. Upon determining the amount of generation resources that would be necessary to achieve a loss of load expectation of less than one occasion every ten years, a reserve margin (expressed as a percentage of peak firm demand) is calculated and assigned to all load serving entities. The MISO LOLE Work Group is in the process of performing an updated study that will cover the 12-month period beginning June 1, 2013.

Q. What capacity planning reserve margin target is appropriate for the planning period?

A. For the 12-month period beginning June 1, 2012, the MISO LOLE Working Group determined that, absent consideration of forced outages, a capacity planning reserve margin target (or "unforced" capacity planning reserve margin target) for MISO of at least 3.79% was sufficient to satisfy ReliabilityFirst Corporation's ("RFC") capacity planning criteria of expecting to interrupt firm load no more frequently than one occasion in 10 years. RFC is the regional reliability organization that represents the North American Electric Reliability Corporation ("NERC") in portions of the MISO footprint and portions of the area served by other regional transmission organizations. NERC is the electric reliability organization appointed by the Federal Energy Regulatory Commission ("FERC") to establish, monitor and enforce reliability standards in the United States. MISO currently uses Planning Resource Credits ("PRC") to demonstrate compliance with the target. However, effective June 1, 2013 MISO will use Zonal Resource Credits ("ZRC") to demonstrate compliance with the target. We anticipate that generators will be awarded ZRCs in the same amount and manner as PRCs but may not be transferable for use in zones different than the zone in which the generator is located.

For purposes of my testimony in this plan case both PRCs and ZRCs may be applicable depending on the time period discussed. Given the relatively minor differences between ZRCs and PRCs my reference to PRCs should be interpreted as reference to PRC or ZRC as appropriate for the time period. The Company has assumed for purposes of this plan case that the 3.79% planning reserve margin target will be applicable for all periods addressed in this plan.

Q. How is Consumers Energy planning to meet the 3.79% reserve target?

A. To facilitate compliance with the planning reserve margin target, MISO has established PRCs which are a measure of each resource's available capacity after discounting for the resource's effective forced outage rate. One PRC of capacity is expected to be sufficient to serve one MW of forecasted demand, providing an adequate discount for generator forced outages. Within the MISO's footprint, Consumers Energy, as a Load Serving Entity ("LSE"), is required to comply with the 3.79% unforced capacity reserve margin requirement by having PRCs equal to monthly firm peak demand times 1.0379 for each month beginning in June 2012. This reserve margin provides an adequate reserve to cover load forecast error, weather variability and transmission contingencies while considering the benefits that result from demand diversity over the MISO footprint. PRCs eliminate the potential for double counting MISO market participant's resources within the MISO's market footprint through tariff requirements on market participants to use the Module E Capacity Tracking ("MECT") tool.

Q. How do you determine the amount of PRCs needed for the peaking season?

A. To determine the amount of PRCs represented by the capacity planning reserve margin target we utilize the demand forecast prepared by Mr. Warriner. Mr. Warriner's forecast of 8,344 MW of demand shown on Exhibit A-20 (LDW-3), page 1, line 13 and on Exhibit A-13 (DFR-1), line 28, includes jurisdictional and nonjurisdictional demand from the Company's distribution and wholesale customers adjusted for the PRCs expected to be offset by energy optimization, direct load management, and dynamic peak pricing programs. Mr. Warriner also prepares an estimate of the amount of demand expected to be offset by Retail Open Access suppliers of 579 MW as shown on Exhibit A-20 (LDW-3), page 2, line 13 and Exhibit A-13 (DFR-1), line 29. Additionally, part of the forecasted demand is expected to be avoided under the Company's interruptible service provision (Provision GI) and thus avoid the cost of reserving PRCs during periods of peak demand. Based on our experience from 2012 we have estimated that 124 MW of interruptible service will be provided during the planning period as shown on Exhibit A-13 (DFR-1), line 21. Based on these assumptions the resulting demand expected to be served with PRCs of 7,765 MW is shown on Exhibit A-13 (DFR-1), line 30. The 431 MW difference between the PRCs for total capacity on line 25 and the demand expected to be served with PRCs on line 30 represents the amount of PRCs available to satisfy the capacity planning reserve margin target and is shown on Exhibit A-13 (DFR-1), line 31.

Q. Do you anticipate any changes to the Planning Reserve Margin in 2013?

A. Yes. MISO is expected to issue their Planning Reserve Margin requirements for the Planning year beginning June 1, 2013 by November 1, 2012. Any change from the Planning Reserve Margin applicable for the planning year 2013 will cause an adjustment in the required capacity resources.

RESOURCES ALREADY ACQUIRED FOR 2013

Q. What resources are required to meet the 3.79% seasonal reserve margin target?

A. Lines 1 through 25 of Exhibit A-13 (DFR-1) provide a description of the resources currently available to the Company and the resources that are expected to be acquired by Consumers Energy to achieve the 3.79% capacity planning reserve margin under peak load conditions. In 2013, the Company expects to have 5,644 of PRCs from its owned units during the peak load period (Consumers Energy is a summer-peaking system) as shown on Line 5, Column (a) of Exhibit A-13 (DFR-1). The Company also has long-term contracts with several Non-Utility Generators ("NUG"s) for 2,428 PRCs as shown on Line 20 Column (a) of Exhibit A-13 (DFR-1). The Company also expects its Load Modifying Resources ("LMRs") to qualify for 128 MW of PRCs as shown on line 24, column (a) of A-13 (DFR-1). Those resources, when compared to the forecast of peak demand expected to be served with 7,765 PRCs as shown on Line 30, Column (a) of Exhibit A-13 (DFR-1), provide a reserve margin of 5.56% as shown on Line 32, Column (a) of Exhibit A-13 (DFR-1).

RESOURCES PREVIOUSLY APPROVED BY THE COMMISSION

Q. To what extent have the owned resources providing 5,644 PRCs and NUG resources providing 2,428 PRCs been included in previous PSCR plans?

A. Owned resources providing 5,644 PRCs and NUG resources providing 2,428 PRCs have been included in previous PSCR plans and approved by the Commission, most recently in MPSC Case Nos. U-16432.

Q. What resources included in Exhibit A-13 (DFR-1) have been approved by the Commission but not included in previous PSCR plan cases?

A. There are no contracts or Company owned resources that have been included in Exhibit A-13 (DFR-1) and have been approved by the Commission but not included in previous PSCR plan cases.

RESOURCES NOT PREVIOUSLY APPROVED BY THE COMMISSION

Q. What resources included in Exhibit A-13 (DFR-1) have not yet been approved by the Commission?

A. There are Company owned resources that have been included in Exhibit A-13 (DFR-1) that have not previously been approved by the Commission. They include:

- The Company is in the process of planning for the construction of the Cross Winds Energy Park with approximately 150 MW schedule to begin operation in late 2014 or 2015. We anticipate submitting the wind turbine supply, the engineering, procurement and construction, and the transformer procurement contracts for Commission approval in 2012 or 2013; and
- The Company is in the process of expanding the Experimental Advanced Renewable Program adding approximately 3.25 MW of solar powered generating systems between 2012 and 2015.

RESOURCES REMAINING TO BE PURCHASED FOR 2013

Q. Does Consumers need to acquire additional capacity for summer 2013?

A. No. However, due to the proposed cessation of service of Weadock Units 7 and 8; Whiting Units 1, 2, and 3; and Cobb Units 4 and 5, effective April 1, 2015, the Company will need to purchase from others or otherwise acquire approximately 900 MW in 2015, 950 MW in 2016 and 1,000 MW in 2017 in order to meet the planning reserve margin requirement.

MISO CAPACITY MARKET

Q. In MPSC Case No. U-16890 you discussed MISO's Resource Adequacy Construct. Did FERC approve the MISO's enhanced resource adequacy proposal?

A. Yes. On June 11, 2012, FERC issued an order accepting MISO's resource adequacy proposal with an effective date of October 1, 2012.

Q. What are the Company's options for meeting its planning resource requirements?

A. The Company can meet its planning resource requirements by: 1) participating in the Planning Resource Auction ("PRA"); 2) self-scheduling resources into the PRA; or 3) opting out of the PRA by submitting a fixed resource adequacy plan ("FRAP").

Q. Please explain the self-scheduling option.

A. The self-scheduling option will allow the Company to offer its capacity resources into the PRA at a price of zero or more and then bid to purchase the same amount of resources. Capacity resources will be ranked from lowest offer to highest offer. Lowest offer resources will be awarded until capacity requirements are met and then all capacity resources offered at the offer price of the last awarded resource or less will be paid the last awarded offer price. Similarly, all bids to purchase capacity at or above the last awarded capacity offer will be charged the last awarded offer price. If the Company selects the self-schedule option, we anticipate the Company will offer its resources into the PRA at a price of zero or near zero. By doing so it would be left financially indifferent because it would be buying and selling the same amount of capacity through the auction at the same capacity price.

Q. Please explain the opt-out options?

A. The Company can opt-out of the auction by submitting a FRAP. A FRAP will identify the resources that the Company has ownership or contractual rights to that will be relied upon to meet the Company's Planning Reserve Margin requirement. The Company's own resources or contractual commitments for resources that are in excess of its FRAP may be offered into the auction. Conversely, if the Company's FRAP does not cover all of its resource requirements it will be required to make up any shortfall through the auction.

Q. When will the initial planning year begin?

A. The initial planning year will be the 12 month period beginning June 1, 2013.

Q. When will MISO conduct its initial PRA?

A. The PRA offer window will be open the last three business days of the month of March 2013. MISO will then post the results the fifth business day of the following month (April).

Q. Will the Company participate in the monthly auctions prior to the start of the new planning year?

A. Yes. The Company plans to continue to participate in the current monthly Voluntary Capacity Auction process through May 2013.

Q. How will these costs and revenue be treated in the PSCR cases?

A. Capacity costs and revenues incurred during the period June 1, 2013 through December 31, 2013 will be subject to reconciliation in the PSCR reconciliation case for 2013. Capacity costs and revenues during the January 1, 2014 through May 31, 2014 period will be included in the 2014 PSCR plan and be subject to reconciliation in the 2014 PSCR reconciliation case.

Q. How does the annual resource requirement impact Consumers Energy's capacity procurement process?

A. Historically, the Company has procured additional seasonal capacity for the summer months to meet Resource Adequacy requirements although the Company's plan for 2013 does not anticipate such a purchase to be necessary. Under the new MISO Resource Adequacy construct, the Company may be required to purchase additional capacity for an annual period i) to effectively "buy back" capacity offered through the self-schedule process or ii) to supplement existing capacity to satisfy resource margin or ZRC requirements that will not be established until later this year or early next year. MCL460.6j(13)(b) may require the Company to obtain Commission approval of these capacity charges because the term of the purchase exceeds six months.

Q. What is the Company requesting with respect to Section 6j(13(b)?

A. To the extent section 6j(13)(b) applies to purchase of ZRC's acquired through MISO's Forward Capacity Market process, the Company is requesting that the MPSC approve the capacity purchases made to meet the Company's resource adequacy requirements for the 2013 Planning Year.

SYSTEM SUPPORT RESOURCE

Q. Please explain System Support Resource ("SSR") and attachment Y.

A. An SSR is a generation unit that must be available for MISO to operate the transmission grid within applicable reliability standards. Any MISO Market Participant planning to retire or mothball a generation resource located in the MISO region must notify MISO by submitting an attachment Y at least twenty-six weeks prior to initiating the process. When MISO receives the attachment, it performs a study without the specific generating unit in-service. If MISO determines that the resource is needed to maintain power system reliability, then the owner of the generation resource and MISO will enter into an agreement which will keep the unit in service.

Q. Will the Company have any units designated as a SSR in 2013?

A. Yes. In my supplemental testimony for U-16890, I stated that the Company planned to remove Gaylord units 1, 2 3, and 4 and the Straits combustion turbines from service, effective March 1, 2012. On February 14, 1012, however, the Company received notice from MISO that its transmission study showed that by removing these units it would create a violation of its reliability standards. As a result, these units would need to be designated as SSRs until the appropriate transmission upgrades are made.

Q. Will the Company be compensated?

A. The Company will receive compensation for any fixed and variable operating and maintenance expense that could have been avoided through retirement or suspension (mothball) of their resources.

Q. How will MISO allocate these costs?

A. Costs will be allocated to the load serving entities that benefit from the operation of the SSR unit.

Q. What is the length of an SSR service agreement?

A. The agreement will have a term of twelve months.

Q. Can the agreement be extended?

A. Yes. MISO will periodically review the reliability requirements of its region and determine if any SSR agreements need to be extended.

Q. How will the SSR costs impact PSCR costs?

A. SSR fixed and variable operating costs and revenues received from MISO will be reconciled through the PSCR reconciliation.

BLACK START SERVICE

Q. Please explain “Black Start” service.

A. Black start service is the process of restoring generation resources without relying on the external electric power network. Generating units using steam turbines require station service power of up to 10% of their capacity for boiler feedwater pumps, boiler forced-draft combustion air blowers, and for fuel preparation. It is uneconomical to provide such a large standby capacity at each station, so black-start power must be provided over designated tie lines from another station. To provide a black start, some generation facilities have small diesel generators which can be used to start larger generators, which in turn can be used to start the main power station generators.

Q. Will the Company have any generation resources designated for Black Start service in 2013?

A. Yes. On October 14, 2010, the Company temporarily removed Thetford Units 1, 2, 5, 6, and 7 as well as Weadock Unit A and Whiting Unit A from service for a three year period which will end October 14, 2013. On August 1, 2011, the Company advised MISO that the Thetford units 3, 4, 8 & 9 would be removed from service effective February 1, 2012. In its May 11, 2012 response approving removal of Thetford units 3, 4, 8 & 9 from service, MISO noted that these units were part of Michigan Electric Transmission Company's ("METC") system restoration plan and referred the matter to METC. METC and the Company have been negotiating an agreement that may keep one or more units in service for an undetermined period of time. The Company is in the process of evaluating whether other, currently mothballed, units could be designated for Black Start service after they are brought back into service in lieu of maintaining Thetford units 8 & 9 for Black start service. For purposes of this filing, however, the Company assumes that Thetford 4, 5, 8 & 9 units will be included METC Black Start plan.

Q. How will the Company be compensated for its Black Start services?

A. The Company should be compensated for the costs incurred in maintaining black start service capability; however, no agreement exists at this time.

Q. How will Black Start service costs and revenue be treated in the PSCR cases?

A. Black Start service costs and revenues received from METC will be reconciled through the PSCR reconciliation.

TEMPORARY REMOVAL OF SMALL COMBUSTION TURBINES FROM SERVICE

Q. What is the Company's future strategy for temporarily removing certain combustion turbine generating units from service?

A. The Company will continue to evaluate both its portfolio of resources and load forecast. Based on its current forecasts, the Company will adjust its portfolio to economically meet summer 2013 peak load and beyond.

Q. What is the current retirement strategy?

A. Previously, the Company temporarily removed Thetford Units 1, 2, 5, 6, and 7 as well as Weadock Unit A and Whiting Unit A from service for the three year period beginning October 14, 2010 and ending October 14, 2013. The Company is in the process of evaluating whether some of these units should be returned to service. For purposes of this filing, however, the Company assumes that all of these units will be retire from service.

MIDWEST ENERGY MARKETS

Q. With regards to serving Consumers' bundled load, will all of the charges incurred and revenues received by Consumers Energy under the MISO's Transmission and Energy and Operating Reserves Market Tariff be included in net PSCR costs to be recovered from Consumers' PSCR customers in 2013 and later years?

A. Yes. All of the expense incurred with MISO and all of the revenues received from MISO, to the extent the revenues received were from the output of jurisdictional facilities sold to MISO, are expected to be included in PSCR costs reconciled in the Company's 2013 PSCR reconciliation case.

Q. Please enumerate these costs and revenues seen on a normal settlement statement.

A. Exhibit A-14 (DFR-2) is a listing of the line items of settlement on a normal day.

Q. What are some of the key charges that Consumers Energy sees on the settlement statement?

A. Based on the experience with the Market to date, Consumers is seeing the largest level of costs and revenues in charges associated with FTRs and Auction Revenue Rights ("ARR") (Line 13 through 24 of Exhibit A-14 (DFR-2)), Asset Energy (Lines 2 and 26 of Exhibit A-14 (DFR-2)), Revenue Neutrality Uplift (Line 36 of Exhibit A-14 (DFR-2)), Revenue Sufficiency Guarantee (Lines 10, 11, 37 and 38 of Exhibit A-14 (DFR-2)), and Uninstructed Deviation (Line 39 of Exhibit A-14 (DFR-2)).

Q. Has the amount of settlement been forecasted for any of these charges?

A. Yes. Mr. Burgdorf has forecasted expenditures for (i) Day-Ahead Market Administration Amount, (ii) Financial Transmission Rights Market Administration Amount, and (iii) Real-Time Market Administration Amount. He was able to make such forecasts because MISO has projected a settlement rate for each of these charges.

Q. Have the other Market charges been forecasted?

A. Yes. Consumers Energy estimates the gross marginal energy price expected to be paid or charged by MISO using methods we've previously used to estimate the prices experienced in bilateral markets. Consumers Energy will include all settled charges incurred and revenues received in the 2013 PSCR reconciliation case.

Q. If MISO makes a change to settlement charges after the 2013 PSCR reconciliation case is resolved, how will Consumers Energy account for the change?

A. The expense or revenue associated with any settlement, net of any reserves established for such settlement, will be booked in the year that the settlement occurs. As a result, those charges will be included in the then-current PSCR reconciliation case.

Q. Is the Company forecasting or expecting a major settlement?

A. Yes. The Company has been advised by MISO that a claim has been submitted by Detroit Edison alleging that an incorrect meter calculation associated with service to the Wyandotte system has adversely affected their revenue. The Company has reviewed the matter and anticipates that in accordance with MISO's Alternative Dispute Resolution ("ADR") tariff provision, a resettlement of market charges incurred by the Company is likely to occur after this case is filed.

Q. Who is responsible for the calculation of the energy interchange between Consumers Energy's and Detroit Edison's service territories?

A. International Transmission Company ("ITC") as the local balancing authority is responsible for energy interchange calculation.

Q. What was the residual energy miscalculation that may impact 2013 PSCR expenses?

A. From October 1, 2008 until July of 2012, ITC miscalculated the residual energy for Consumers Energy and Detroit Edison due to an error in the energy interchange calculation. The error resulted in Consumers Energy's customers paying for less energy than they actually used and Detroit Edison's customers paying for more energy than they actually used. The resulting MISO billing settlement adjustment may occur in 2013.

Q. What is the expected cost of the billing settlement adjustment?

A. The expected cost to Consumers Energy's customers is $30.2 million. The Company believes that it will be billed for this amount in 2012. The Company expects to have collected approximately $6 million of this amount through the 2012 PSCR monthly factor and the remainder in 2013. This is reflected in Exhibit A-2 (NNB-1).

RENEWABLE RESOURCE PROGRAM

Q. Are you familiar with the Renewable Resource Program ("RRP")?

A. Yes. The RRP was approved by the Commission in January 2005 in MPSC Case No. U-13843. Under this program the Company contracts to purchase energy generated by renewable technologies and then allocates the cost of that energy between power supply costs recoverable from PSCR customers and renewable energy costs to be recovered from either voluntary contributions from customers or the Renewable Resource Fund. The Renewable Resource Fund is funded in part by a contribution from the Midland Cogeneration Venture Limited Partnership in accordance with a settlement agreement filed and approved by the Commission in MPSC Case No. U-15320.

Q. How are RRP costs treated in this PSCR plan?

A. In accordance with the Commission's orders in MPSC Case No. U-13843, Consumers Energy has adjusted the cost of energy delivered from the RRP generators to the average PSCR cost calculated before considering the energy delivered by the RRP suppliers themselves. This cost will be recovered from the Company's PSCR customers. The remainder of the cost contracted to be paid to RRP suppliers that remains unrecovered after such adjustment will be recovered from contributions paid by customers who voluntarily participate in the Renewable Resources Program (if any) and then from the Renewable Resource Fund created in MPSC Case No. U-13843, *supra*. In this way, the inclusion of the costs associated with these contracts will have no effect on the PSCR factor in accordance with the Commission's May 18, 2004 order in that case.

RENEWABLE ENERGY PLAN

Q. Are you familiar with the Company's Renewable Energy Plan?

A. Yes. The Company's Renewable Energy Plan ("RE Plan") was approved by the Commission in its May 26, 2009 order in MPSC Case No. U-15805. The RE Plan addresses the measures necessary to comply with MCL 460.1001 et seq. The RE Plan was amended with the Commission's May 10, 2011 Order in MPSC Case No. U-16543. The Plan was amended a second time with the Commission's May 1, 2012 Order in MPSC Case No. U-16581 approving the settlement agreement in the Company's RE Plan Biennial Review.

Q. To what extent have the cost of resources used to satisfy the requirements of MCL 460.1001 et seq. been included in the Company's PSCR plan?

A. In accordance with MCL 460.1001 et seq. and the Company's approved RE Plan, the Company's PSCR plan includes (i) all of the cost of renewable energy resources for which recovery in rates was approved as of October 6, 2008 and (ii) that portion of the cost of renewable energy resources for which recovery in rates was not approved as of October 6, 2008 ("new resources") that represents the value of the energy, capacity, and ancillary services those resources are expected to deliver to the Company. All additional costs are expected to be recovered as Incremental Cost of Compliance through the Renewable Energy Surcharge.

Q. On what basis was the value of energy from new resources determined?

A. In general, the Company's estimate of the value of energy delivered through power purchase agreements is based on the lower of (i) the monthly schedule of average on-peak and off-peak locational marginal prices included with the application for approval of the related agreement and (ii) the actual forecast expense associated with the resource. In the case of all solar photovoltaic agreements, the estimate is based on the lower of (i) the monthly schedule of average on-peak locational marginal prices included with the application for approval of the related agreement and (ii) the actual forecast expense associated with the resource. Agreements approved by the Commission on or before May 10, 2011 utilize the monthly schedule of average on-peak and off-peak locational marginal prices shown on pages 15 and 16 of Exhibit A-14 (DFR-7) in MPSC Case No. U-15805. No new contracts were approved by the Commission between May 10, 2011 and May 1, 2012. Contracts not approved before May 1, 2012 utilize the monthly schedule of average on-peak and off-peak locational marginal prices shown on lines 14 through 39 of page 2 of Exhibit A-32 (JSR-5) in MPSC Case No. U-16581. The Company's estimate of the value of energy delivered by new Company owned facilities is determined using the same monthly schedules of on-peak and off-peak locational marginal prices, but is not limited to the actual forecast expense associated with the facility. In most cases the volume of energy delivered from the various new resources is based on the expected annual or monthly capacity factors appropriate for the various technologies.

Q. On what basis was the value of capacity from new resources determined?

A. For resources approved by the Commission on or before May 10, 2011, the value of capacity for new resources is based on the schedule of capacity costs included as pages 59 and 60 in Exhibit A-14 (DFR-7) in MPSC Case No. U-15805. No new resources were approved by the Commission between May 10, 2011 and May 1, 2012. For resources not approved by the Commission as of May 1, 2012, the value of capacity for new resources is based on the schedule of capacity costs included on page 3 in Exhibit A-32 (JSR-5) in MPSC Case No. U-16581. The amount of capacity to be delivered by each new resource is expected to be the amount of unforced capacity expected to be approved by MISO increased by the system average forced outage rate.

Q. On what basis was the value of ancillary services from new resources determined?

A. No value for ancillary services for new resources were included in the Renewable Energy Plan or this PSCR plan because of the minimal amount of experience the Company had with MISO's Ancillary Service Market and the amount of ancillary services expected to be provided by these resources at the time the Renewable Energy Plan was prepared.

ENERGY EFFICIENCY AND DEMAND MANAGEMENT PROGRAM

Q. Are you familiar with the Company's plan to implement an Energy Optimization Program?

A. Yes. In MPSC Case No. U-15805, the Company proposed to implement an Energy Efficiency Optimization program expected to reduce the need to acquire capacity and generate electricity. The Energy Optimization Program was revised in MPSC Case No. U-16412 and is proposed to be revised again in MPSC Case No. U-16670.

Q. Have you forecasted any adjustments to address the Energy Optimization program?

A. Yes. As discussed by Mr. Warriner, the Company has estimated the reduction of energy consumption and demand during peak load conditions for energy efficiency programs and included those reductions in the forecast included in the 2013 PSCR plan.

Q. What additional adjustments have been forecasted?

A. Mr. Warriner has also made an adjustment to demand during peak load conditions for Dynamic peak pricing and Direct Load Management programs, which is forecasted on Exhibit A-13 (DFR-1) on Lines 22 and 23.

SUMMARY

Q. Please summarize your testimony.

A. My testimony explains the need to maintain a capacity planning reserve margin target and advises the Commission that for purposes of this PSCR plan, the Company has used a Capacity Planning Reserve Margin target of 3.79%. I have demonstrated that the Company is proceeding to acquire adequate resources in 2013 to meet the load and Capacity Planning Reserve Margin requirements to supplement resources previously approved by the Commission. I have discussed the Company's plans to provide adequate capacity for future years. I have advised the Commission of the types of charges expected to be incurred with the Midwest Energy Market and their inclusion in the PSCR plan. I have advised the Commission that the PSCR plan includes the costs incurred under the RRP only to the extent allowed by the Commission's orders. I have advised the Commission that the PSCR plan included certain costs incurred under the Renewable Energy Plan on to the extent that those costs are less than or equal to the amount paid and the Company's estimate, as approved by the Commission, of the energy and capacity value provided by the resource. I have advised the Commission that adjustments for Energy Optimization, direct load management, and dynamic peak pricing programs have been incorporated into the PSCR plan consistent with the Company's prior applications.

Q. Does this complete 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 Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

EXHIBITS

OF

DAVID F. RONK, JR

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17133
Witness: DFRonk Jr.
Exhibit: A-13 (DFR-1)
Date: September 2012
Page: 1 of 1

CONSUMERS ENERGY COMPANY
SUMMER PEAK PROJECTED PLANNING RESOURCE CREDITS, DEMAND, AND MARGINS

Line	Description	(a) 2013	(b) 2014	(c) 2015	(d) 2016	(e) 2017
1	PRCs for Owned Capacity					
2	Net Demonstrated Capability less EFORd	5,629.4	5,644.2	5,660.6	4,800.4	4,843.8
3	PRCs for Projected Unit Upgrades/Re-ratings/Additions	0.0	16.4	22.8	-3.8	14.3
4	PRCs for Projected Retirements/remove/return from/to service	14.8	0.0	-883.0	47.2	0.0
5	Subtotal PRCs for Owned Capacity	5,644.2	5,660.6	4,800.4	4,843.8	4,858.1
6	PRCs for Transactions: (Annual Contracted Amounts)					
7	PRCs for Projected Summer Capacity Purchases	0.0	0.0	900.0	975.0	1000.0
8	PRCs for Projected Self Generation/Load Shift	0.0	0.0	0.0	0.0	0.0
9	Subtotal PRCs for Purchases	0.0	0.0	900.0	975.0	1000.0
10	PRCs for Non-Utility Generation Projects (NUGs)					
11	PRCs for MCV Contract Capacity	1,186.0	1,186.0	1,186.0	1,186.0	1,186.0
12	PRCs for Palisades PPA	762.0	762.0	762.0	762.0	762.0
13	PRCs for Other NUGs	421.0	421.0	421.0	404.0	403.0
14	PRCs for PA 295 Wind NUGs	39.7	39.7	39.7	39.7	39.7
15	PRCs for PA 295 Landfill Gas NUGs	15.3	15.3	15.3	15.3	13.8
16	PRCs for PA 295 Anaerobic Digestion NUGs	3.9	3.9	3.9	2.3	2.3
17	PRCs for PA 295 Existing Solar NUGs	0.0	0.5	0.5	0.5	1.0
18	PRCs for PA 295 New EARP Solar NUGs	0.0	0.3	0.5	0.7	2.2
19	PRCs for PA 295 Hydro NUGs	0.3	0.3	0.3	0.3	0.3
20	Subtotal PRCs for NUGs	2,428.2	2,429.0	2,429.2	2,410.8	2,410.3
	PRCs for Load Modifying Resource					
21	Demand from Interruptible Customers	124.0	124.0	124.0	124.0	124.0
22	Smart Grid-Dynamic Peak Pricing	0.0	0.0	32.0	56.0	79.0
23	Demand expected to be offset by Direct Load Control/Demand response (AC Cycling)	4.0	16.0	29.0	41.0	56.0
24	Subtotal PRCs for Load Modifying Resources	128.0	140.0	185.0	221.0	259.0
25	Total PRCs	8,196.4	8,213.6	8,253.6	8,353.6	8,392.4
26	Peak Demand Forecast (Absent Energy Efficiency & Direct Load Control)	8,465.0	8,681.0	8,827.0	8,959.0	9,048.0
27	Demand expected to be offset by Energy Efficiency	-117.0	-177.0	-238.0	-248.0	-257.0
28	Resulting Peak Demand Forecast*	8344.0	8488.0	8560.0	8670.0	8735.0
29	Demand expected to be served by Retail Open Access Suppliers	-579.0	-581.0	-581.0	-577.0	-577.0
30	Demand to be served with PRC Capacity (coincident)	7,765.0	7,907.0	7,947.0	8,037.0	8,079.0
31	Margin -- MW	431	307	307	317	313
32	Margin Reserve -- %	5.56%	3.88%	3.86%	3.94%	3.88%

*See Exhibit A-20 (LDW-3), page 1, line 13

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-17133
Witness: DFRonk Jr.
Exhibit: A-14 (DFR-2)
Date: September 2012

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR (MISO)
ENERGY MARKET SETTLEMENT CHARGE LINE ITEMS

Line	Charge Line Item Description
1	Day Ahead Market Administration Amount
2	Day Ahead Asset Energy Amount
3	Day Ahead Financial Bilateral Transaction Congestion Amount
4	Day Ahead Financial Bilateral Transaction Loss Amount
5	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts
6	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts
7	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts
8	Day Ahead Losses Rebate on Option B Grandfathered Agrmnts
9	Day Ahead Non-Asset Energy Amount
10	Day Ahead Revenue Sufficiency Guarantee Distribution Amount
11	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt
12	Day Ahead Virtual Energy Amount
13	Auction Revenue Rights Transaction Amount
14	Financial Transmission Rights Annual Transaction Amount
15	Auction Revenue Rights Infeasible Uplift Amount
16	Auction Revenue Rights Stage 2 Distribution Amount
17	Financial Transmission Rights Full Funding Guarantee Amount
18	Financial Transmission Rights Guarantee Uplift Amount
19	Financial Transmission Rights Market Administration Amount
20	Financial Transmission Rights Hourly Allocation Amount
21	Financial Transmission Rights Monthly Allocation Amount
22	Financial Transmission Rights Monthly Transaction Amount
23	Financial Transmission Rights Transaction Amount
24	Financial Transmission Rights Yearly Allocation Amount
25	Real Time Market Administration Amount
26	Real Time Asset Energy Amount
27	Real Time Financial Bilateral Transaction Congestion Amount
28	Real Time Financial Bilateral Transaction Loss Amount
29	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts
30	Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts
31	Real Time Distribution of Losses Amount
32	Real Time Miscellaneous Amount
33	Real Time Non-Asset Energy Amount
34	Real Time Net Inadvertent Distribution Amount
35	Real Time Price Volatility Make Whole Payment Amount
36	Real Time Revenue Neutrality Uplift Amount
37	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount
38	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt
39	Real Time Uninstructed Deviation Amount
40	Real Time Virtual Energy Amount
41	Day Ahead Schedule 24 Allocation Amount
42	Real Time Schedule 24 Allocation Amount
43	Real Time Schedule 24 Distribution Amount
44	Day Ahead Regulation Amount
45	Day Ahead Spinning Reserve Amount
46	Day Ahead Supplemental Reserve Amount
47	Contingency Reserve Deployment Failure Penalty Amount
48	Excessive Energy Amount
49	Net Regulation Adjustment Amount
50	Non-Excessive Energy Amount
51	Real Time Regulation Amount
52	Regulation Cost Distribution Amount
53	Real Time Excessive Deficient Energy Deployment Charge Amount
54	Real Time Spinning Reserve Amount
55	Spinning Reserve Cost Distribution Amount
56	Real Time Supplemental Reserve Amount
57	Supplement Reserve Cost Distribution Amount

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	)	Case No. U-17133
for Approval of a Power Supply Cost	)	
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Factors for the Year 2013	)	

DIRECT TESTIMONY

OF

SARA T. WALZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

Q. Please state your name and business address.

A. Sara T. Walz, 1945 West Parnall Road, Jackson, Michigan.

Q. By whom are you employed?

A. Consumers Energy.

Q. In what capacity are you employed?

A. I am a General Engineering Technical Analyst in the Transactions and Resource Planning Section of the Energy Supply Operations Department.

Q. Please briefly describe your educational background.

A. I received a Bachelor of Arts Degree in Mathematics in 2006 from Michigan State University and a Master of Science Degree in Applied Mathematics in 2007 from North Carolina State University.

Q. Please describe your business and professional experience.

A. I joined Consumers Energy's Transactions and Resource Planning department in January 2008. I was responsible for the Financial Transmission Rights ("FTR") monthly and annual allocation and auction. I maintained the Company's FTR portfolio, successfully reducing congestion expenses, which in turn reduced Power Supply Cost Recovery ("PSCR") expenses by $6.5 million over one year. In September 2009, I began working in the Production Cost Modeling area of Transactions and Resource Planning. Since that time, I have been the primary modeler for near term fuel and purchased power expenses using the PROMOD production cost modeling software. During my time in this role, I have assisted in the development of the workpapers and exhibits for Richard J. Polena who has provided testimony in previous PSCR Plan cases. I have also been responsible for comparing actual monthly peak demand to the Company's forecast of monthly peak demand and determining if, in accordance with the tariff under which the Midwest Independent Transmission System Operator, Inc. ("MISO") provides service, the forecasted monthly peak demand was under-forecasted. I have presented topics related to weather normalization techniques in load forecasting at the 2011 Itron User's conference in Phoenix, AZ.

Q. What are your present responsibilities and duties as a General Engineering Technical Analyst?

A. Presently I am responsible for modeling and analysis of fuel and purchased and net interchange power costs that are used in developing the PSCR Plan and updating the PSCR factor. Additionally I am responsible for replacement power cost analysis, generation unit outage analysis, fuel strategy scenario development and other related matters.

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

A. The purpose of my testimony is to forecast costs of fuel and purchased and net interchange power needed to fulfill the Company's system requirements. These costs are shown on a monthly basis for 2013 and on a yearly basis for 2013 through 2017.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibits A- 15 (STW-1) through A-17 (STW-3).

Q. What are the Company's forecasts of 2013 costs of fuel and purchased and net interchange power to fulfill system requirements?

A. This forecast is shown in Exhibit A-15 (STW-1), Pages 1-3.

Q. Do you consider the forecast data set forth in this exhibit to be a reasonable forecast for 2013?

A. Yes, I do. This plan was developed using an economic dispatch computer program, which is used to produce the Company's budget and operating forecasts for fuel and purchased and net interchange power. This 2013 forecast was produced using up-to-date assumptions and data that were reviewed by the responsible departments before they were input to the program. The results have been reviewed for reasonableness and for consistency with input and assumptions.

Q. Did you use the same production costing program for this case as was used for the Company's 2012 PSCR Plan Case, MPSC Case No. U-16890?

A. Yes. I used the PROMOD Production Costing Program for this case.

Q. Please describe Exhibit A-15 (STW-1) further.

A. This exhibit shows the energy from the various resources and the costs of supplying such energy. The information for 2013 is provided both on a month-by-month and annual basis.

Q. How were these figures derived?

A. They were derived from the PROMOD program, which simulates the dispatch of the Company's generating resources and purchased and interchange power resources to meet projected customer requirements. Pages 1-3 of Exhibit A-15 (STW-1) show the monthly results for 2013, which were then totaled to obtain the annual results, which are also shown on Exhibit A-16 (STW-2) along with the years 2013 through 2017. The main inputs to PROMOD were projected system loads, system generation requirements, unit heat rates, maintenance schedules, unit random outage rates, fuel costs, unit net demonstrated capabilities, and purchased and interchange power availability and costs. The PROMOD model is structured to align as closely as possible with the way that MISO dispatches the system.

Q. Who provided you with the input data relating to projected system loads and system generation requirements?

A. The data was provided to me by Mr. Warriner, and his testimony and exhibits set forth and explain the relevant assumptions and calculations.

Q. What was the source of your input information for fuel costs?

A. Coal, oil and natural gas costs were provided by Mr. Chilson, a witness in this case.

Q. Who provided input information for the Consumers Energy generating units?

A. That information was provided by Mr. Kehoe, also a witness in this case.

Q. Are there any major changes to Consumers Energy's owned units for this PSCR case?

A. Yes. There is the addition of 100.8 MW of nameplate wind capacity at the Lake Winds Energy Park assumed to be in-service beginning on October 31, 2012 and the addition of 150 MW of nameplate wind capacity at the Cross Winds Energy Park assumed to be in-service beginning on December 31, 2015. This new wind capacity was most recently included in the Company's Renewable Energy Plan filing in MPSC Case No. U-16543, that was approved by the Commission on May 10, 2011. Also included in this PSCR plan case is an upgrade to the Ludington 4 unit resulting in an increase in generating capacity of 25.5 MW assumed to be in-service beginning May 1, 2014; an upgrade to the Ludington 5 unit resulting in an increase in generating capacity of 25.5 MW assumed to be in-service beginning May 1, 2015; an upgrade to the Ludington 1 unit resulting in an increase in generating capacity of 25.5 MW assumed to be in-service beginning May 1, 2016 and an upgrade to the Ludington 2 unit resulting in an increase in generating capacity of 25.5 MW assumed to be in-service beginning May 1, 2017. These upgrades are part of the major unit overhaul project at the Ludington Pumped Storage Plant beginning in 2013.

Q. What other major changes to Consumers Energy's owned units are included in this PSCR?

A. This PSCR plan case reflects the Company's decision to suspend the operation of seven of the Consumers Energy coal units (Cobb 4 and 5, Weadock 7 and 8, and Whiting 1, 2, and 3) beginning on April 1, 2015. This case also reflects the Company's decision to mothball the following combustion turbine units: the Campbell Unit A and the Morrow Units A and B beginning on February 15, 2012; and the Thetford Units 3, 4, 8, and 9 beginning on May 14, 2012.

Q. On Line 4 of Exhibit A-15 (STW-1) you use the term "Station Power." Please explain that term.

A. Station Power is the amount of electricity that a generating unit uses to operate its own generating unit components such as motors, pumps, lighting, heating, etc. When a generating unit is operating, all of the station power is subtracted from the gross output of the generating unit to provide the net output that is reported on lines 1 and 2. When a generating unit is off-line, station power usage is accounted for as negative generation. Lines 1 and 2 reflect the steam generation after subtracting the forecasted station power used while off line as well. The total system requirement on Line 13 includes station power used while off line, so I show a separate line item to balance the exhibit.

Q. On Line 11 of Exhibit A-15 (STW-1) you use the term "Purchased (NUGs)." Please explain that term.

A. That term refers to forecasted purchases of energy from non-utility generators with whom the Company has Power Purchase Agreements. A list of the entities that power is projected to be purchased from for the years 2013 through 2017 is found on Exhibit A-17 (STW-3), Pages 1-18, under the headings "Existing Energy-Only Agreements," "Green Generation

Program Agreements," "Existing Energy & Capacity Agreements" and "Renewable Energy Plan Agreements." This exhibit also outlines the rates for such purchases and the duration of the contracts.

Q. How were purchases from the suppliers listed on Exhibit A-17 (STW-3) estimated?

A. The estimate was made using one of two methods.

1. For nondispatchable suppliers, we have a history of deliveries so the historical monthly average was used.
2. For dispatchable suppliers, the respective power purchase agreements state that Consumers Energy can vary the hourly energy purchased from the supplier from a stated minimum up to the amount of capacity available at the time, not to exceed the contract capacity. These suppliers were dispatched in a manner similar to our own generating units and interchange sources.

Q. Are there any changes in the existing sources of purchased power for this PSCR case?

A. Yes, the Heritage Garden Wind Farm I and the Heritage Stoney Corners Wind Farm II contracts that were approved by the Commission in its November 19, 2010 order in MPSC Case No. U-15805 were amended as described in Consumers Energy's filing of December 12, 2011 in MPSC Case No. U-15805-E. The Heritage Garden Wind Farm I is scheduled to be in-service on September 14, 2012 with a nameplate rating of 20.0 MW. The Heritage Stoney Corners Wind Farm I Phase 2 began commercial operation on January 1, 2012 with a nameplate rating of 12.25 MW, and the Heritage Stoney Corners Wind Farm I Phase 3 began commercial operation on January 1, 2012 with a nameplate rating of 8.35 MW.

Q. Are there new sources of purchased power for this PSCR case?

A. No.

Q. Are there any other sources of purchased power for this PSCR case?

A. Yes, the existing Experimental Advanced Renewable Program (EARP) is modeled in this case. This consists of 2 MW of nominal solar capacity assumed to be in-service as of 2012. This program is a result of the Company's Renewable Energy Plan, as approved by the Commission in its May 26, 2009 order in MPSC Case No. U-15805.

Q. Is the new Expanded EARP modeled in this case?

A. Yes, this is modeled as 3 MW of nominal solar capacity, phased in starting in October of 2012 and continuing until all 3 MW are in-service by October of 2015, as explained in a filing made on July 8, 2011 in MPSC Case No. U-16543.

Q. Are the Renewable Resource Program suppliers included in this PSCR case?

A. Yes, the Renewable Resource Program approved by the Commission in its January 25, 2005 order in MPSC Case No. U-14843 is modeled in this case. The suppliers are comprised of wind and landfill gas units and are shown on Exhibit A-17 (STW-3) listed under the category of Green Generation Program Agreements. The energy charge for all the Green Generation contracts that is recoverable in the PSCR is the average PSCR rate for the year.

Q. Are there any changes in the representation of the MCV in this case?

A. No, the MCV facility is again dispatched and its energy is priced according to the terms in the Settlement Agreement that was approved by the Commission in its June 20, 2008 order in MPSC Case No. U-15320.

Q. Are there any changes in the representation of any of the other Non-Utility Generators?

A. No. As in last year's Case No. U-16890, the Cadillac, Genesee, and Grayling wood fired units are again dispatched on a wood price, and the Ada unit is again dispatched on the cost of production based on natural gas, instead of the twelve month rolling average coal price that is the contract dispatch price for these units. The Reduced Dispatch Agreements (RDAs) for the wood fired units were most recently included as Exhibit A-38 (DFR-12) in Case No. U-15001-R. The Reduced Dispatch Agreement for the Ada unit was most recently included as Exhibit A-20 (DFR-4) in Case No. U-16045. The hold harmless amount resulting from this dispatch is $247,000 and the customer benefit (offset to PSCR) is $112,000. These amounts are included as credits in lines 24 and 38 on Exhibit A-15 (STW-1) and Exhibit A-16 (STW-2).

Q. On Line 12 of Exhibit A-15 (STW-1) you use the term "Net Interchange." Please explain this.

A. This phrase refers to purchases from and sales to other entities. The details are shown on Exhibit A-15 (STW-1) and also on Exhibit A-16 (STW-2), pages 2 and 3. Lines 27 and 28 detail the energy received and lines 31 through 33 detail the energy delivered. Lines 36 and 37 detail the costs for energy received and lines 42 through 45 detail the revenues for energy delivered. Line 35 details the purchase of Zonal Resource Credits (ZRC's) to meet the MISO reserve margin requirements. This is explained in Mr. Ronk's testimony. Lines 27, 28, 36 and 37 detail the purchase of on peak and off peak energy from the market. This represents the MISO market from which we buy power on a daily or hourly basis. Lines 31 and 42 represent the sale of energy to the MISO market.

Q. Please explain line 40.

A. Line 40 represents the payments to the Biomass Merchant Plants in excess of the Company's avoided cost as required under 2008 PA 286 and the Commission's August 11, 2009 order in MPSC Case No. U-16048.

Q. Please explain lines 32 and 44.

A. Lines 32 and 44 represent a sale to the MISO market from our oil and gas units. This is an estimate of the sale associated with the MISO RAC (Reliability Assessment Commitment) process. MISO must ensure that sufficient resources are available and online to meet the forecasted MISO load for each hour of the next operating day. We have estimated the amount of increased generation at the oil and gas units that MISO uses for this purpose on line 32 and have represented it as a sale. We have assumed that we will be reimbursed in full for this use of our units and therefore this increased generation cost is fully offset by the revenue shown on line 44 and therefore does not affect the PSCR factor.

Q. Please explain line 43.

A. Line 43 represents revenue from the sale of capacity, although no sales have been modeled in this case.

Q. Does the Company have agreements with other entities that involve transactions classified as "Purchased and Interchange Power"?

A. No.

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	)	
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EXHIBITS

OF

SARA T. WALZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-17133
EXHIBIT: A-15 (STW-1)
WITNESS: STWALZ
DATE: SEPTEMBER, 2012

CONSUMERS ENERGY COMPANY

SUMMARY BY SOURCE

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2013
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	ENERGY (MWH)													
1	COAL STEAM	1,474,713	1,321,369	1,130,900	1,019,684	1,142,607	1,202,650	1,481,329	1,443,864	1,196,255	884,480	1,178,586	1,222,969	14,699,406
2	GAS & OIL	363,863	331,114	220,061	123,901	188,344	314,314	369,224	367,114	251,380	209,881	193,354	102,250	3,034,801
3	NUCLEAR PPA	586,539	528,454	583,840	559,091	572,083	548,945	563,423	562,165	547,245	578,182	565,146	584,700	6,779,813
4	STATION POWER	8,444	9,287	12,726	12,265	9,628	8,253	5,577	5,760	7,792	13,999	8,772	8,898	111,400
5	CE OWNED RENEWABLES	66,552	57,939	72,073	76,561	66,653	51,993	42,550	39,206	39,645	50,327	57,937	63,118	684,553
6	PEAKERS	0	0	0	0	0	3,140	61,094	35,110	0	0	0	0	99,344
7	PUMPED STORAGE	51,748	30,703	48,967	107,142	104,172	100,827	144,385	129,010	63,518	27,209	32,467	74,379	914,526
8	TOTAL GENERATED	2,551,860	2,278,867	2,068,567	1,898,644	2,083,487	2,230,121	2,667,581	2,582,230	2,105,834	1,764,078	2,036,261	2,056,314	26,323,844
9	LESS : PUMPING	-61,322	-37,687	-79,688	-145,785	-138,582	-152,195	-192,029	-184,268	-91,234	-34,108	-47,102	-115,641	-1,279,640
10	TOTAL GENERATED	2,490,538	2,241,180	1,988,879	1,752,859	1,944,905	2,077,926	2,475,552	2,397,962	2,014,601	1,729,970	1,989,160	1,940,673	25,044,204
11	PURCHASED (NUGs)	702,540	647,856	345,040	328,711	457,170	497,797	697,693	614,804	386,666	328,798	336,502	355,444	5,699,020
12	NET INTERCHANGE	-18,525	-71,593	584,076	660,780	463,135	592,379	321,043	506,352	567,214	931,904	497,761	919,337	5,953,863
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13	TOTAL SYSTEM REQUIREMENTS	3,174,553	2,817,443	2,917,995	2,742,350	2,865,210	3,168,102	3,494,287	3,519,118	2,968,481	2,990,672	2,823,422	3,215,454	36,697,088
	EXPENSES ($*1000)													
14	COAL STEAM	44,861	39,855	34,976	30,986	35,165	37,315	48,841	47,126	36,872	27,162	35,670	37,330	456,159
15	GAS & OIL	11,021	10,074	6,903	4,035	5,981	9,748	13,494	13,754	8,005	6,748	6,518	3,923	100,205
16	NUCLEAR PPA	30,897	23,961	25,318	24,734	25,927	29,065	33,424	33,295	28,991	25,602	24,409	26,126	331,749
17	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
18	CE OWNED RENEWABLES	2,270	1,899	1,851	1,842	1,526	1,272	1,734	1,673	1,140	1,513	1,779	1,969	20,467
19	PEAKERS	42	42	57	42	42	181	2,508	1,474	42	42	42	42	4,555
20	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
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21	TOTAL GENERATED	89,092	75,831	69,104	61,640	68,641	77,581	100,000	97,321	75,050	61,067	68,419	69,390	913,135
22	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TOTAL GENERATED	89,092	75,831	69,104	61,640	68,641	77,581	100,000	97,321	75,050	61,067	68,419	69,390	913,135
24	PURCHASED (NUGs)	59,399	54,079	45,094	43,258	49,062	49,941	60,420	57,279	42,334	43,121	44,462	46,512	594,962
25	NET INTERCHANGE	-2,040	-3,541	16,042	17,956	9,781	15,290	2,104	8,748	15,005	29,045	15,845	27,346	151,584
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26	TOTAL SYSTEM COST	146,451	126,370	130,241	122,854	127,484	142,812	162,524	163,348	132,390	133,233	128,726	143,248	1,659,682

MICHIGAN PUBLIC SERVICE COMMISSION

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CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2013
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	RECEIVED (MWH)													
27	MARKET ON PEAK	50,139	29,181	217,289	277,664	172,717	235,924	113,926	178,761	239,382	527,098	282,387	424,399	2,748,867
28	MARKET OFF PEAK	124,852	94,261	386,199	395,624	395,712	440,602	513,427	535,897	405,688	411,044	239,088	504,663	4,447,058
29	PURCHASED (NUGs)	702,540	647,856	345,040	328,711	457,170	497,797	697,693	614,804	386,666	328,798	336,502	355,444	5,699,020
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30	TOTAL RECEIVED	877,532	771,298	948,528	1,001,998	1,025,599	1,174,323	1,325,046	1,329,462	1,031,737	1,266,941	857,977	1,284,506	12,894,945
	DELIVERED (MWH)													
31	EXTERNAL SALES	193,516	195,035	19,412	12,508	105,294	84,148	259,908	165,166	77,857	6,238	23,714	9,725	1,152,520
32	MISO RAC	0	0	0	0	0	0	46,402	43,140	0	0	0	0	89,542
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33	TOTAL DELIVERED	193,516	195,035	19,412	12,508	105,294	84,148	306,310	208,306	77,857	6,238	23,714	9,725	1,242,061
34	NET (MWH)	684,016	576,263	929,116	989,491	920,305	1,090,175	1,018,736	1,121,156	953,880	1,260,702	834,262	1,274,781	11,652,884

MICHIGAN PUBLIC SERVICE COMMISSION

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CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2013
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	EXPENSE ($*1000)													
35	PURCHASE OF ZONAL RESOURCE CRI	0	0	0	0	0	0	0	0	0	0	0	0	0
36	MARKET ON PEAK ENERGY	1,411	660	6,960	9,058	5,338	8,865	5,377	7,756	8,871	18,885	10,504	15,127	98,813
37	MARKET OFF PEAK ENERGY	3,476	2,699	9,758	9,307	8,279	9,893	11,914	12,517	9,125	10,373	6,045	12,556	105,940
38	PURCHASED (NUGs) ENERGY	37,319	34,078	23,581	22,409	26,827	28,405	38,118	35,029	23,668	22,579	23,040	24,271	339,323
39	PURCHASED (NUGs) CAPACITY	21,254	19,255	20,721	20,020	21,359	20,651	21,322	21,282	17,805	19,658	20,572	21,349	245,250
40	CASE NO. U-16048 COST RECOVERY	825	746	792	830	876	885	981	967	861	884	850	892	10,390
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41	TOTAL EXPENSE	64,286	57,438	61,812	61,624	62,679	68,699	77,711	77,551	60,330	72,379	61,011	74,195	799,715
	CREDIT ($*1000)													
42	EXTERNAL SALE ENERGY	6,926	6,900	676	408	3,836	3,472	12,060	8,024	2,991	213	703	333	46,542
43	EXTERNAL SALE CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
44	MISO RAC	0	0	0	1	0	-4	3,126	3,501	0	0	0	3	6,627
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45	TOTAL CREDIT	6,926	6,900	676	409	3,835	3,468	15,186	11,525	2,991	213	703	337	53,169
46	NET EXPENSE	57,359	50,539	61,137	61,214	58,844	65,232	62,525	66,027	57,340	72,166	60,307	73,858	746,546

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO.: U-17133
EXHIBIT: A-16 (STW-2)
WITNESS: STWALZ
DATE: SEPTEMBER, 2012

CONSUMERS ENERGY COMPANY

SUMMARY BY SOURCE

YEAR		2013	2014	2015	2016	2017
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	ENERGY (MWH)					
1	COAL STEAM	14,699,406	16,141,591	12,606,706	10,748,100	11,408,614
2	GAS & OIL	3,034,801	2,149,841	2,839,675	2,825,297	2,539,679
3	NUCLEAR PPA	6,779,813	6,778,836	6,780,138	6,798,738	6,780,463
4	STATION POWER	111,400	100,155	90,343	89,505	80,506
5	CE OWNED RENEWABLES	684,553	684,621	685,657	1,224,015	1,213,908
6	PEAKERS	99,344	72,476	98,350	104,029	102,373
7	PUMPED STORAGE	914,526	923,871	942,978	1,075,259	1,152,152
8	TOTAL GENERATED	26,323,844	26,851,390	24,043,848	22,864,943	23,277,695
9	LESS : PUMPING	-1,279,640	-1,275,851	-1,278,731	-1,430,841	-1,522,605
10	TOTAL GENERATED	25,044,204	25,575,539	22,765,116	21,434,102	21,755,090
11	PURCHASED (NUGs)	5,699,020	4,702,436	5,048,316	4,983,676	4,861,906
12	NET INTERCHANGE	5,953,863	7,151,987	10,175,381	12,508,925	12,563,557
		--------	--------	--------	--------	--------
13	TOTAL SYSTEM REQUIREMENTS	36,697,088	37,429,961	37,988,813	38,926,703	39,180,552
	EXPENSES ($*1000)					
14	COAL STEAM	456,159	477,293	366,930	331,145	360,630
15	GAS & OIL	100,205	82,594	110,991	115,459	110,751
16	NUCLEAR PPA	331,749	338,601	345,706	356,190	365,295
17	STATION POWER	0	0	0	0	0
18	CE OWNED RENEWABLES	20,467	21,254	22,627	53,767	54,586
19	PEAKERS	4,555	3,806	5,232	5,735	5,917
20	PUMPED STORAGE	0	0	0	0	0
		------	------	------	------	------
21	TOTAL GENERATED	913,135	923,547	851,486	862,297	897,179
22	LESS : PUMPING	0	0	0	0	0
23	TOTAL GENERATED	913,135	923,547	851,486	862,297	897,179
24	PURCHASED (NUGs)	594,962	558,236	573,578	578,243	591,469
25	NET INTERCHANGE	151,584	206,878	391,121	530,884	548,501
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26	TOTAL SYSTEM COST	1,659,682	1,688,661	1,816,185	1,971,424	2,037,150

MICHIGAN PUBLIC SERVICE COMMISSION

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CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2013	2014	2015	2016	2017
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	RECEIVED (MWH)					
27	MARKET ON PEAK	2,748,867	3,601,250	5,347,032	6,296,882	6,183,568
28	MARKET OFF PEAK	4,447,058	4,265,925	5,274,884	6,482,351	6,617,217
29	PURCHASED (NUGs)	5,699,020	4,702,436	5,048,316	4,983,676	4,861,906
		--------	--------	--------	--------	--------
30	TOTAL RECEIVED	12,894,945	12,569,611	15,670,231	17,762,909	17,662,691
	DELIVERED (MWH)					
31	EXTERNAL SALES	1,152,520	617,898	350,327	175,546	143,020
32	MISO RAC	89,542	97,291	96,207	94,763	94,209
		------	-------	------	-------	-------
33	TOTAL DELIVERED	1,242,061	715,189	446,534	270,308	237,229
34	NET (MWH)	11,652,884	11,854,422	15,223,697	17,492,601	17,425,462

MICHIGAN PUBLIC SERVICE COMMISSION

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CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2013	2014	2015	2016	2017
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**
	EXPENSE ($*1000)					
35	PURCHASE OF ZONAL RESOURCE CR	0	0	49,361	90,715	98,602
36	MARKET ON PEAK ENERGY	98,813	140,967	220,574	270,739	273,283
37	MARKET OFF PEAK ENERGY	105,940	101,057	145,260	188,902	194,774
38	PURCHASED (NUGs) ENERGY	339,323	299,757	313,744	323,099	338,464
39	PURCHASED (NUGs) CAPACITY	245,250	246,308	246,309	242,065	241,189
40	CASE NO. U-16048 COST RECOVERY	10,390	12,171	13,524	13,079	11,815
		------	------	------	------	------
41	TOTAL EXPENSE	799,715	800,261	988,773	1,128,599	1,158,127
	CREDIT ($*1000)					
42	EXTERNAL SALE ENERGY	46,542	26,376	15,280	10,062	8,683
43	EXTERNAL SALE CAPACITY	0	0	0	0	0
44	MISO RAC	6,627	8,771	8,794	9,409	9,473
		------	------	------	------	------
45	TOTAL CREDIT	53,169	35,147	24,074	19,472	18,157
46	NET EXPENSE	746,546	765,114	964,699	1,109,127	1,139,970

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Existing Energy–Only Agreements	Projected 2013 Rates	Termination of Agreement
1	Great Lakes Tissue Company	Energy: Three-month rolling average incremental running cost Administrative Charge: 0.10¢/kWh	Terminated by mutual consent or by either party giving the other at least six months' written notice of its desire to terminate the Agreement at the end of any yearly period.
2	Jackson County	Energy: Three-month rolling average incremental running cost Administrative Charge: 0.10¢/kWh	Seller may terminate by giving at least 180 days written notice to Consumers. Consumers may terminate if the Seller breaches the contract, or if the Seller is in default of any of its obligations for longer than 90 days.
3	Michigan State University	Energy: Three-month rolling average incremental running cost Administrative Charge: 0.10¢/kWh (not to exceed $200/month)	Terminated by mutual consent or by either party giving the other at least 30 days' written notice of its desire to terminate the Agreement at the end of any yearly period.
4	Western Michigan University	Energy: Hourly incremental running cost Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month)	Terminated by mutual consent or by either party giving the other at least 30 days' written notice of its desire to terminate the Agreement at the end of any monthly period.
5	Grand Valley State University	Energy: 90% of the hourly incremental running cost Administrative Charge: None	Terminated by mutual consent or by either party giving the other at least 30 days' written notice of its desire to terminate the Agreement at the end of any monthly period.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Existing Energy–Only Agreements	Projected 2013 Rates	Termination of Agreement
6	City of Midland, MI	Energy: 90% of Consumers Energy's Real Time Load Node LMP Minus \$5/MWh Administrative Charge: 0.10¢/kWh (minimum of \$343/month, but not to exceed \$3,429/month)	Terminated by mutual consent or by either party giving the other at least 30 days' written notice of its desire to terminate the Agreement at the end of any monthly period.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Green Generation Program Agreements	Projected 2013 Rates	Termination of Agreement
1	Michigan Wind I LLC (Wind) (PPA 1)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month)	December 18, 2018. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.
2	Michigan Wind I LLC (Wind) (PPA 2)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month)	December 18, 2028. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.
3	Bay Windpower I, Mackinaw City, LLC. (Wind)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month).	December 3, 2018. After this date, the agreement shall automatically renew for subsequent one year periods and shall continue in effect until terminated by mutual agreement or by either party giving the other party at least one year’s written notice of termination.
4	Rathbun Generating Station (Landfill Gas)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month).	January 29, 2018.

Line	Green Generation Program Agreements	Projected 2013 Rates	Termination of Agreement
5	North American Natural Resources, Inc. Venice Park Generating Station (Landfill Gas)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month).	February 10, 2026. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.
6	Zeeland Farm Services, Inc. (Landfill Gas)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month).	February 17, 2013.
7	Gas Recovery Systems, LLC. C&C Electric 2 Plant (Landfill Gas)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month).	February 28, 2027. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination.

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
1	Ada Cogeneration Ltd Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.024¢/kWh On-Peak 3.822¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	January 5, 2026. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
2	Adrian Energy Associates	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.476¢/kWh On-Peak 4.253¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	December 13, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
3	Gas Recovery Systems (formerly, Alternative Power Limited Partnership)	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month)	February 20, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
4	Cadillac Renewable Energy	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.320¢/kWh On-Peak 4.110¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	July 16, 2028. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
5	WM Renewable Energy, LLC. (formerly Bio Energy Partners)	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.19¢/kWh On-Peak 3.98¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $200/month, but not to exceed $2,000/month)	May 4, 2027. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of any yearly period.
6	Black River Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 1.97¢/kWh On-Peak 1.67¢/kWh Off-Peak Administrative Charge: 0.125¢/kWh	December 31, 2017. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
7	Beaverton, City of	Energy: 3.81¢/kWh On-Peak 2.99¢/kWh Off-Peak Capacity: 3.51¢/kWh On-Peak 2.75¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2023. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
8	Hope Renewable Energy – Hubbardston	Energy: Agreement Terminated. Capacity: Agreement Terminated. Administrative Charge: Agreement Terminated.	This agreement was terminated on November 8, 2011.
9	Commonwealth Power Company – Irving	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.034¢/kWh On-Peak 3.832¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	August 25, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
10	Commonwealth Power Company – LaBarge	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.39¢/kWh On-Peak 3.84¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2017. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
	Commonwealth Power Company –		

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
11	Middleville	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.034¢/kWh On-Peak 3.832¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	January 1, 2031. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
12	Genesee Power Station Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.65¢/kWh On-Peak 4.42¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $200/month, but not to exceed $2,000/month)	December 13, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of any yearly period.
13	Granger Electric Company – Grand Blanc	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.402¢/kWh On-Peak 4.182¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month)	July 27, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
14	Granger Electric of Pinconning	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.348¢/kWh On-Peak 4.136¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $235/month, but not to exceed $2,349/month)	January 22, 2028. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective on January 22 of any year.
15	Granger Electric of Byron Center	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.184¢/kWh On-Peak 3.970¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $256/month, but not to exceed $2,562/month)	April 10, 2026. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective on April 10 of any year.
16	Granger Electric Company – Ottawa	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month)	June 21, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
	Granger Electric Company –		

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
17	Seymour	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month)	November 21, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
18	Grayling Generating Station Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.18¢/kWh On-Peak 3.97¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month)	December 31, 2027. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
19	Grenfell Hydro, Inc	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.02¢/kWh On-Peak 3.42¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2018. After this date the Agreement may continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
	Hillman Power Company LLC	Energy: Twelve-month rolling average	December 31, 2015. After this date the Agreement may

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
20		cost of CE coal generation Capacity: 3.85¢/kWh On-Peak 3.27¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	continue until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
21	Kent County	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 5.34¢/kWh On-Peak 4.54¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	February 11, 2022. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
22	Michiana Hydroelectric Co Bellevue	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 5.36¢/kWh On-Peak 4.76¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2018. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
23	Michigan Power Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 3.880¢/kWh On-Peak 3.686¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	October 23, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
24	Midland Cogeneration Venture Limited Partnership	Energy: Cost of Production Capacity: 1.014¢/kWh Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	March 16, 2025. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
25	North American Natural Resources, Inc.- (Peoples)	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month)	September 8, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination.
26	STS Hydropower Ltd – Cascade Hydro Plant	Energy: 3.81¢/kWh On-Peak 2.99¢/kWh Off-Peak Capacity: 4.25¢/kWh On-Peak 3.61¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2018. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
27	STS Hydropower Ltd –	Energy: 3.81¢/kWh On-Peak	December 31, 2017. After this date the Agreement may

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
	Fallasburg Hydro Plant	2.99¢/kWh Off-Peak Capacity: 3.09¢/kWh On-Peak 2.63¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
28	STS Hydropower Ltd – Morrow Hydro Plant	Energy: 3.81¢/kWh On-Peak 2.99¢/kWh Off-Peak Capacity: 3.97¢/kWh On-Peak 3.37¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2019. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
29	T.E.S. Filer City Station Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 6.28¢/kWh On-Peak 5.33¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh (not to exceed $2,000/month)	June 17, 2025. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year.
30	Thornapple Association, Inc	Energy: 3.81¢/kWh On-Peak 2.99¢/kWh Off-Peak Capacity: 3.35¢/kWh On-Peak 2.85¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2016. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
31	Viking Energy of Lincoln Limited Partnership	Energy: Twelve-month rolling average	December 31, 2018. After this date the Agreement may

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
		cost of CE coal generation Capacity: 4.30¢/kWh On-Peak 3.66¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
32	Viking Energy of McBain Limited Partnership	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 4.30¢/kWh On-Peak 3.66¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2018. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
33	White's Bridge Hydro Company	Energy: Twelve-month rolling average cost of CE coal generation Capacity: 3.76¢/kWh On-Peak 3.20¢/kWh Off-Peak Administrative Charge: 0.10¢/kWh	December 31, 2016. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period.
34	Boyce Hydro (formerly Wolverine Power Corporation)	Energy: 5.12¢/kWh On-Peak 2.17¢/kWh Off-Peak Capacity: 0.91¢/kWh On-Peak 0.77¢/kWh Off-Peak Administrative Charge: None	May 31, 2022.
35	Entergy Nuclear Power Marketing, LLC	Energy: 0.603¢/kWh	April 11, 2022.

Line	Existing Energy & Capacity Agreements	Projected 2013 Rates	Termination of Agreement
		Capacity: 4.297¢/kWh Administrative Charge: None	
36	North American Biofuels – Green Meadow Farms	Energy: Real Time Locational Marginal Cost Capacity: 0.70¢/kWh Administrative Charge: None	March 1, 2013.

Line	Renewable Energy Plan Agreements	Projected Rates	Termination of Agreement
1	Elk Rapids Hydroelectric Power LLC	Energy: Monthly Transfer Rate Administrative Charge: None	October 12, 2019.
2	Scenic View Dairy LLC, Freeport Plant (Anaerobic Digestor)	Energy: Monthly Transfer Rate Administrative Charge: None	December 31, 2015.
3	Zeeland Farm Services Inc, Plant 2 (Landfill Gas)	Energy: Monthly Transfer Rate Administrative Charge: None	October 12, 2016.
4	Fremont Community Digestor LLC (Anaerobic Digestor)	Energy: Monthly Transfer Rate Administrative Charge: None	20 years after commercial operation date. Commercial operation is projected as November 1, 2012.
5	WM Renewable Energy LLC, Northern Oaks Landfill Plant (Landfill Gas)	Energy: Monthly Transfer Rate Administrative Charge: None	November 10, 2030.
6	North American Natural Resources Inc, Lennon Generating Station (Landfill Gas)	Energy: Monthly Transfer Rate Administrative Charge: None	December 15, 2030.

Line	Renewable Energy Plan Agreements	Projected Rates	Termination of Agreement
7	Michigan Wind 2 (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	December 31, 2031.
8	Harvest II Wind Farm (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	20 years after commercial operation date. Commercial operation is projected as December 31, 2012.
9	Blissfield Wind Energy (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	20 years after commercial operation date. Commercial operation is projected as December 31, 2012.
10	WM Renewable Energy LLC, Pine Tree Acres Landfill Plant (Landfill Gas)	Energy: Monthly Transfer Rate Administrative Charge: None	February 28, 2032.
11	Heritage Stoney Corners Wind Farm I, LLC, Phase 2 (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	December 31, 2031.

Line	Renewable Energy Plan Agreements	Projected Rates	Termination of Agreement
12	Heritage Stoney Corners Wind Farm I, LLC, Phase 3 (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	December 31, 2031.
13	Heritage Garden Wind Farm I, LLC (Wind)	Energy: Monthly Transfer Rate Administrative Charge: None	20 years after commercial operation date. Commercial operation is projected as September 15, 2012.
14	Scenic View Dairy Fennville Plant (Anaerobic Digester)	Energy: Average PSCR rate Administrative Charge: 0.10¢/kWh (minimum of $343/month, but not to exceed $3,429/month).	December 31, 2015. Consumers Energy filed for and received approval as a PA 295 contract (Renewable Energy Plan) on October 26, 2010 in MPSC Case No.U-15805.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

DIRECT TESTIMONY

OF

LINCOLN D. WARRINER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

Q. Please state your name and business address.

A. My name is Lincoln D. Warriner, and my business address is One Energy Plaza, Jackson, Michigan.

Q. By whom are you employed?

A. Consumers Energy Company (hereinafter, “the Company").

Q. What is your position with the Company?

A. I am a Senior Business Support Consultant - Lead in the Rates and Business Support Department.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Business Administration, major in Accounting, from Central Michigan University in 1987. In 1994, I received a Master of Science in Administration Degree from Central Michigan University.

Q. What is your business experience?

A. I began working for the Company in June 1987 as a region accountant at the Grand Rapids Service Center. While there, I performed various reviews of internal accounting control procedures and workflow processes. In 1989, I transferred to a similar position at the Lansing Service Center. In 1991, I took a position as a Management Systems and Planning Analyst in the Southern Region Administration and Planning Department. My primary responsibility in this position was to provide analytical support to region management on issues concerning operating, maintenance, and construction budgets and other performance measurements. In February 1994, I took a position as an Administrative Supervisor responsible for the supervision of several administrative functions including region accounts payable, miscellaneous accounts receivable, cash receipts and disbursements, payroll, records center, and mail room operations. In February 1995, I transferred to the Electric SBU Planning Department, which since has been consolidated within the Rates and Business Support Department. In this department, I have been responsible for coordinating the development of financial plans, budgets, analysis, and forecasts for the Electric SBU. Since 1997, my responsibilities have included the electric deliveries forecast, and completing various financial and economic studies for the Electric business unit. During 2007 I accepted additional supervisory responsibility for the Company's gas deliveries forecasts and electric revenue forecasts.

Q. Have you testified in other cases before the Michigan Public Service Commission (the "Commission")?

A. Yes. I have recently provided testimony in the following cases:

a. U-16191 – January 2010 electric rate case. I presented adjustments to 2008 historical actual sales and revenues for the purpose of developing the projected test year sales and revenue. I also presented the Company's forecast of electric deliveries, generation requirements, and peak demand for the years 2009-2013.

b. U-16412 – September 2010 energy optimization plan amendment. I explained the historical and forecasted sales and revenue data that the Company used in developing its amended Energy Optimization Plan.

c. U-16418 – August 2010 gas rate case. I adopted the testimony of Linda J. Clark regarding the Company's forecast of gas deliveries and provided rebuttal testimony concerning adjustments to the Company's forecast that were proposed by interveners in that case.

d. U-16432 – September 2010 power supply cost recovery plan case. I presented the Company's official forecasts of electric deliveries, generation requirements, and peak demand forecasts for 2011-2015.

e. U-16543 – February 2011 renewable energy plan amendment. I explained the historical and forecasted sales and revenue data that the Company used in developing its amended renewable energy plan.

f. U-16794 – June 2011 electric rate case. I presented adjustments to 2010 historical actual sales and revenues for the purpose of developing the projected test year sales and revenue. I also presented the Company's forecast of electric deliveries, generation requirements, and peak demand for the years 2011-2015.

g. U-16670 – August 2011 energy optimization plan amendment. I explained the historical and forecasted sales and revenue data that the Company used in developing its amended Energy Optimization Plan.

h. U-16890 – September 2011 & February 2012 power supply cost recovery plan case. I presented the Company's official forecasts of electric deliveries, generation requirements, and peak demand forecasts for 2012 – 2016.

i. U-16924 – December 2011 gas cost recovery plan case. I presented the Company's official forecasts of natural gas sales and natural gas transportation for 2012 – 2016.

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

A. My purpose is to present Consumers Energy's official forecasts of electric deliveries, generation requirements, and peak demand for the years 2013 - 2017.

Q. What is your relationship to the development of the electric deliveries, generation requirements, and peak demand forecasts?

A. I am responsible for the overall development of the electric deliveries, generation requirements, and peak demand forecasts. My responsibilities include coordination of the collection of needed information from internal and external sources, and development of forecast models and forecast data. I am also responsible for refining and updating the methods used to develop the forecast when appropriate.

This forecast includes projections of load to be supplied by alternate energy suppliers as well as load to be supplied by Consumers Energy. Because load supplied by alternate energy suppliers is included, this forecast is referred to as a forecast of total electric deliveries. Retail open access deliveries and full service sales are subsets of total electric deliveries presented in this forecast.

The forecasts presented also include adjustments to the forecast to reflect the planned impact of the Company's Energy Optimization Plan, as well as peak demand reductions expected from planned direct load management and dynamic peak pricing programs. Also, as in the past, these forecasts include jurisdictional and non-jurisdictional sales.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibits A-18 (LDW-1) through A-22 (LDW-5).

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

A. Yes.

Q. Please describe Exhibits A-18 (LDW-1) and A-19 (LDW-2).

A. Page 1 of Exhibit A-18 (LDW-1) identifies the monthly calendar forecast of the Company's electric deliveries by customer class for the year 2013. Page 2 identifies the retail open access portion of the monthly calendar forecast and Page 3 identifies the full service portion of the monthly calendar forecast. Page 1 of Exhibit A-19 (LDW-2) shows the annual cycle-billed forecast of the Company's electric deliveries by customer class for the years 2013 through 2017. Pages 2 and 3 subdivide the cycle-billed forecast into retail open access and full service components respectively.

Q. What is the difference between calendar deliveries and cycle-billed deliveries?

A. The difference is due to timing. Cycle-billed sales reflect usage based on when meters are read and usage is billed. Calendar sales reflect usage during a specific calendar month or year. Due to the nature of the Company's meter reading schedule, cycle-billed sales lag Calendar month sales. The difference between cycle-billed sales and calendar sales for any time period is known as unbilled sales. Projected unbilled sales are forecast at a total system level considering indicators of the differences between the billing cycle duration and the number of calendar days in a specific time period, as well as differences in indicators of calendar month and billing month heating degree days and cooling degree days. Unbilled sales projections are then allocated to each class using proportional ratios developed from the cycle-billed sales forecast. As I mentioned, the numbers shown on A-18 (LDW-1) are calendar sales and the numbers shown on A-19 (LDW-2) are cycle-billed.

Q. Please describe generally how these projections of cycle-billed deliveries were made.

A. The forecast reflects a separate projection for each customer class and, where appropriate, analyzes certain classes in more detail. Projection techniques vary from category to category based upon the availability of information, the accuracy required in the forecast, and the need to determine the influence of specific input assumptions for each category.

Forecast methodology was the combined result of regression (statistical) models, customer input, and professional judgment. The forecast was based primarily on regression analysis. Independent variables in the regression analysis include economic variables that are obtained from a separate economic forecast, weather variables, and trend variables. In addition, the impacts of future factors, or "forward-looking" items (such as expected customer use changes due to the Company's Energy Optimization Plan, and the expected introduction of Plug-In Hybrid Electric Vehicles) not fully present in past data, are applied as adjustments to the forecast when appropriate.

Q. How has the Company's Energy Optimization Plan been reflected in the electric deliveries forecast?

A. Adjustments for energy efficiency were calculated at a customer class level for the Residential, Commercial, and Industrial classes. Cumulative annual impacts for residential Energy Optimization programs were applied directly to the residential usage forecast. Cumulative annual impacts for Energy Optimization programs targeted to business customers were split between the Commercial class forecast and the Industrial class forecast in proportion to usage volumes for each class.

Q. How are the anticipated usage impacts associated with plug-in hybrid electric vehicles reflected in the electric deliveries forecast?

A. The adjustment made to the forecast for plug-in hybrid vehicles (PHEV) considers various independent estimates of plug-in hybrid electric vehicle saturation over a long range time horizon. This analysis starts with an estimate of the U.S. PHEV stock, from which an estimate of electric vehicles served in the Consumers Energy service area was derived. The electric use forecast considers a mix of different electric range vehicles and estimates of utilization for each type of vehicle. The forecast aligns with President Obama's energy policy goal of having 1 million plug-in hybrid electric vehicles in service by 2015.

Q. Please describe how the cycle-billed forecast of residential deliveries was developed.

A. The Residential class forecasts were developed from forecasts of customer growth and average use per customer.

1. Customer statistics were analyzed using a regression model to estimate changes in residential customers based on projected changes in household indicators for the state of Michigan. These Michigan level indicators were further refined to represent the historical and projected trends for the geographic area of Michigan served by Consumers Energy.
2. Average use forecast were developed from regression models that quantify the influence of billing cycle duration, weather conditions, and seasonal factors on the average monthly usage of the residential class. Economic factors such as the average household size, average household income, and electricity price trends are also included. For purposes of this forecast, future weather conditions are

assumed to be equal to a 15-year average of historical weather conditions from 1997 to 2011.

3. The forecast of monthly average use was then multiplied by the forecast of monthly residential customers to project the total residential deliveries. The result of this calculation was then adjusted for the anticipated reductions associated with Energy Optimization programs and appliance and lighting efficiency improvements. Additional loads for plug-in hybrid vehicles are also considered in the forecast.

Q. How was the Commercial Class forecast developed?

A. The Commercial forecast was developed using regression analysis that quantifies the influence of weather conditions, economic conditions, and seasonal factors on monthly commercial class usage. Economic conditions are quantified by electric service area indicators of service sector employment. For purposes of this forecast, future weather conditions are assumed to be equal to a 15-year average of historical weather conditions from 1997 to 2011. Adjustments to the forecast for Energy Optimization programs were also factored into the Commercial class usage forecast.

Q. How was the Industrial Class forecast developed?

A. The industrial class forecasts were developed from forecasts of GM/Delphi/Nexteer customer usage and other industrial customer usage.

1. The GM/Delphi/Nexteer usage forecast was developed using regression analysis that quantifies the influence of Michigan Transportation Equipment employment and seasonal factors on monthly usage of General Motors, Delphi, and Nexteer accounts.

2. The Industrial Other usage forecast was analyzed in two subsets of customer usage. The largest subset utilizes regression analysis to quantify the influence of electric service area manufacturing employment trends, combined with increasing trends in industrial sector use per employee on the quarterly usage of industrial customers other than General Motors, Delphi, Nexteer, and a large producer of polycrystalline silicon. The Industrial Other forecast also includes anticipated industrial class Energy Optimization program reductions. The second subset of the Industrial Other forecast includes a large producer of semiconductor and solar energy components, which is included in the Industrial Other category, but is analyzed individually based on expected monthly maximum billing demands, billing days, hours per day, and load factor considerations. The results of this approach were reconciled with customer developed usage projections provided to the Company. The forecast of rate E-1 economic development sales is derived from this semiconductor and solar energy component producer forecast.

Q. Please describe how other classes of sales were forecasted.

A. Wholesale usage was estimated based on the power supply cost recovery application of Alpena Power Company in MPSC Case number U-16880.

Streetlighting usage was forecast using the August 2011 light inventory levels for various types of lighting fixtures. Energy consumption is estimated by multiplying the number of each type of fixture by its associated wattage and the number of operating hours in each billing month.

Interdepartmental usage was forecast using actual monthly usage results for the twelve month time period ending August, 2011.

Q. What growth rates are reflected in the forecast shown on Page 1 of Exhibit A-19 (LDW-2)?

A. The compound average annual growth rates are shown on Page 1 of Exhibit A-19 (LDW-2). The starting point for the forecasted growth rate is 2013. The growth rates shown on the exhibit, however, are not used to forecast sales. Growth rates are calculated after the forecast has been developed.

Q. Please comment generally upon the growth patterns shown on Page 1 of Exhibit A-19 (LDW-2).

A. Overall, the projected average growth of 1.5% annually for the period 2013-2017 is a modest increase from the 0.2% annual average historical change that has been experienced from 2003-2013. The projected growth for the forecast period is different than historical changes in growth for a variety of reasons.

Residential sales are projected to increase at an average 0.3% per year from 2013-2017, which is about the same as the average 0.1% yearly rate of growth from 2003-2013. The reasons for this projected modest growth rate include slow household growth in our service area, the planned energy savings resulting from the Company's Energy Optimization plan, and national end-use efficiency standards.

Commercial sales are projected to grow at an average rate of 0.7% per year, up from the -0.2% decline experienced during the 2003-2013 time period. The slow growth rate in the commercial sales class reflects both the economic expectations for Michigan and Energy Optimization energy savings. Industrial sales are projected to grow at an average 3.2% per year from 2013-2017, which represents an improvement from the historical industrial sales growth average of 0.8% per year from 2003-2013 due to several factors. The economic outlook used in this forecast indicates that Michigan manufacturing employment is expected to show growth after the severe decline experienced in 2009. Productivity gains will result in increased manufacturing output, causing electric demand to grow. This growth is offset in part by Energy Optimization usage reductions. The industrial deliveries outlook also reflects continued growth in market demand for polycrystalline silicon, which has resulted in production capacity expansions within our service area.

Q. Please explain how the forecast of electric deliveries is split between retail open access deliveries and full service sales.

A. The Company's level of ROA load is currently capped at 10% of prior year weather-normalized retail deliveries. Customers currently active in retail open access enrolled during 2009, so actual usage for ROA customers for the twelve month period ending December 2011 was used as an estimate of future use. Full service sales are calculated by subtracting the ROA deliveries from the total deliveries forecasted. The 2013 monthly calendar forecast of ROA deliveries is shown on Page 2 of Exhibit A-18 (LDW-1). The full service calendar forecast for 2013 is shown on Page 3 of Exhibit A-18 (LDW-1). The forecast of annual cycle-billed ROA deliveries is shown on Page 2 of Exhibit A-19 (LDW-2). Page 3 of Exhibit A-19 (LDW-2) shows the annual projections of full service cycle-billed sales.

Q. Please describe Exhibit A-20 (LDW-3).

A. Exhibit A-20 (LDW-3) shows projected peak demands for the years 2013-2017. Page 1 of this exhibit shows the peak demand forecast that is consistent with the forecasts of total electric deliveries. Page 2 identifies the reduction from the total deliveries peak associated with the forecast of retail open access deliveries. Page 3 is the remaining full service peak demand to be served by Consumers Energy.

Q. Please describe generally how the projections of monthly peak demand shown on Exhibit A-20 (LDW-3) were developed.

A. The monthly peak forecast was developed as part of a monthly regression analysis that quantifies the influence of base loads, cooling loads, and heating loads. The monthly peak forecast was developed utilizing regression models that quantify the influence of overall changes in energy usage household growth, and high and low daily temperatures on the day of the system peak. For purposes of this forecast, future weather conditions are assumed to be equal to a 15-year average of historical peak day weather conditions from 1997 to 2011. A rank and average method was used to estimate peak day weather conditions for each month.

The Company forecasts chronological hourly demands using MetrixLT load modeling software, which is available from ITRON. MetrixLT is a specialized tool for developing medium and long range load shapes that are consistent with monthly sales and peak forecasts. Separate load shapes were developed to predict hourly estimates of total load before energy efficiency adjustments, retail open access load, Energy Optimization adjustments, direct load control program adjustments, and dynamic peak pricing program adjustments. The full service load shape is then calculated outside the MetrixLT model by subtracting the hourly values for Energy Optimization, direct load control, dynamic peak pricing programs, and ROA load from the hourly total load values.

Q. Please describe how the summer peak demand forecast is adjusted to incorporate the effect of Energy Optimization programs.

A. The peak demand adjustments for Energy Optimization are derived from the Company's Energy Optimization plan.

Q. Are any other adjustments included in the summer peak demand forecast?

A. Yes, there are two programs under development that are expected to reduce load at peak demand times.

The first program, direct load management was initially incorporated into the Company's May 1, 2007 Balanced Energy Initiative filing in Case Number U-15290. In that case, the Company presented load control as an adjustment to the generation resources required to meet the forecasted peak demand. In this plan case forecast, an updated estimate of load control impacts are recognized as part of the Company's peak demand forecast, starting in 2013.

The other program under development is the Company's dynamic peak pricing program. This program is being developed as a component of the Company's Smart Grid project. The forecast includes adjustments for demand response starting in 2015.

Q. Please explain how the projections on Exhibit A-21 (LDW-4) and Exhibit A-22 (LDW-5) were developed for system efficiency, generation requirements, and load factors.

A. System efficiency is projected to remain constant at 92.76%. In other words, the level of line loss is projected to be 7.24% of generation requirements. This estimate was based on the 12 month average system efficiency for the period ending April 2007. Generation requirements are equal to calendar sales divided by system efficiency. Annual load factors are developed by using the following equation: Annual load factor based on the summer peak equals annual generation requirements divided by the product of hours per year multiplied by summer peak demand. Hours in a regular year are 8,760 and hours in a leap year are 8,784.

Q. Does this complete 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 Approval of a Power Supply Cost	)	Case No. U-17133
Recovery Plan and for Authorization of	)	
Monthly Power Supply Cost Recovery	)	
Factors for the Year 2013	)	

EXHIBITS

OF

LINCOLN D. WARRINER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September, 2012

FORECAST OF TOTAL ELECTRIC DELIVERIES
(CALENDAR MONTH - MWh)

Year: 2013

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line		Residential	Commercial	Industrial	Street Lighting	Interdepart-mental	Wholesale	Total
1	January	1,249,677	983,578	981,177	19,295	3,496	25,774	3,262,997
2	February	946,419	865,371	1,047,842	16,661	3,663	21,411	2,901,367
3	March	988,289	942,053	1,059,497	15,573	3,493	27,257	3,036,163
4	April	849,566	874,947	1,096,689	13,383	2,621	24,667	2,861,873
5	May	862,914	911,148	1,180,613	11,715	3,997	25,313	2,995,699
6	June	1,022,005	1,031,319	1,168,299	10,509	3,449	26,798	3,262,378
7	July	1,282,966	1,112,702	1,132,869	11,427	3,897	28,883	3,572,743
8	August	1,281,792	1,119,094	1,162,296	13,337	4,140	28,964	3,609,622
9	September	917,667	974,036	1,169,337	14,806	3,902	27,869	3,107,617
10	October	851,975	1,017,314	1,192,379	17,118	3,838	27,471	3,110,095
11	November	933,492	864,364	1,118,534	18,829	3,146	26,932	2,965,296
12	December	1,199,505	955,754	1,082,209	20,675	4,225	29,319	3,291,687
13	Total	12,386,268	11,651,679	13,391,741	183,328	43,866	320,658	37,977,540

14 Formulas:
15 Line 13 = Line 1 + Line 2 + Line 3 + Line 4 + Line 5 + Line 6 + Line 7 + Line 8 + Line 9 + Line 10 + Line 11 + Line 12
16 Column (h) = Column (b) + Column (c) + Column (d) + Column (e) + Column (f) + Column (g)
17 Exhibit A-18 (LDW-1) Page 1 = Exhibit A-18 (LDW-1) Page 2 + Exhibit A-18 (LDW-1) Page 3

FORECAST OF RETAIL OPEN ACCESS DELIVERIES
(CALENDAR MONTH - MWh)

Year: 2013

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line		Residential	Commercial	Industrial	Street Lighting	Interdepart-mental	Wholesale	Total
1	January	0	90,407	221,286	0	0	0	311,693
2	February	0	80,992	202,626	0	0	0	283,619
3	March	0	89,254	225,109	0	0	0	314,362
4	April	0	83,418	220,674	0	0	0	304,092
5	May	0	91,984	240,620	0	0	0	332,604
6	June	0	93,476	254,937	0	0	0	348,412
7	July	0	101,050	254,576	0	0	0	355,626
8	August	0	98,096	271,653	0	0	0	369,749
9	September	0	92,739	256,642	0	0	0	349,381
10	October	0	86,988	243,571	0	0	0	330,559
11	November	0	88,695	243,804	0	0	0	332,499
12	December	0	87,220	214,789	0	0	0	302,009
13	Total	0	1,084,319	2,850,286	0	0	0	3,934,605

14 Formulas:
15 Line 13 = Line 1 + Line 2 + Line 3 + Line 4 + Line 5 + Line 6 + Line 7 + Line 8 + Line 9 + Line 10 + Line 11 + Line 12
16 Column (h) = Column (b) + Column (c) + Column (d) + Column (e) + Column (f) + Column (g)

FORECAST OF FULL SERVICE DELIVERIES
(CALENDAR MONTH - MWh)

Year: 2013

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line		Residential	Commercial	Industrial	Street Lighting	Interdepart-mental	Wholesale	Total
1	January	1,249,677	893,171	759,891	19,295	3,496	25,774	2,951,304
2	February	946,419	784,379	845,216	16,661	3,663	21,411	2,617,749
3	March	988,289	852,800	834,389	15,573	3,493	27,257	2,721,801
4	April	849,566	791,529	876,015	13,383	2,621	24,667	2,557,781
5	May	862,914	819,164	939,993	11,715	3,997	25,313	2,663,096
6	June	1,022,005	937,843	913,362	10,509	3,449	26,798	2,913,966
7	July	1,282,966	1,011,651	878,293	11,427	3,897	28,883	3,217,117
8	August	1,281,792	1,020,998	890,643	13,337	4,140	28,964	3,239,874
9	September	917,667	881,297	912,695	14,806	3,902	27,869	2,758,236
10	October	851,975	930,325	948,808	17,118	3,838	27,471	2,779,536
11	November	933,492	775,668	874,730	18,829	3,146	26,932	2,632,797
12	December	1,199,505	868,534	867,420	20,675	4,225	29,319	2,989,678
13	Total	12,386,268	10,567,360	10,541,455	183,328	43,866	320,658	34,042,934

14 Formulas:
15 Line 13 = Line 1 + Line 2 + Line 3 + Line 4 + Line 5 + Line 6 + Line 7 + Line 8 + Line 9 + Line 10 + Line 11 + Line 12
16 Column (h) = (Total Generation Requirements - ROA Generation Requirements) x System Efficiency

FORECAST OF TOTAL ELECTRIC DELIVERIES
(CYCLE BILLED - GWh)

Line	(a)	(b) 2013	(c) 2014	(d) 2015	(e) 2016	(f) 2017
1	Residential	12,409	12,374	12,408	12,515	12,572
2	Residential	12,393	12,349	12,376	12,476	12,503
3	PHEV	16	24	32	39	68
4	Commercial	11,672	11,692	11,707	11,907	12,012
5	Industrial	13,352	14,042	14,507	15,070	15,142
6	GM/Delphi/Nexteer	919	989	1,044	1,048	1,013
7	E-1 Economic Development	2,248	2,321	2,321	2,321	2,321
8	Industrial Other	10,186	10,732	11,142	11,701	11,808
9	Street Lighting	183	184	184	185	185
10	Interdepartmental	44	44	44	44	44
11	Wholesale	320	322	324	326	328
12	Total	37,980	38,657	39,174	40,047	40,282

Annual Average Growth Rate (AAR) in Percent

Line		1993 - 2013F	2003 - 2013F	2013F - 2017F
13	Residential	1.0%	0.1%	0.3%
14	Commercial	1.3%	-0.2%	0.7%
15	Industrial	0.7%	0.8%	3.2%
16	Total	0.9%	0.2%	1.5%

17 Formulas:
18 Line 12 = Line 1 + Line 4 + Line 5 + Line 9 + Line 10 + Line 11
19 Line 1 = Line 2 + Line 3
20 Line 5 = Line 6 + Line 7

FORECAST OF RETAIL OPEN ACCESS DELIVERIES
(CYCLE BILLED - GWh)

Line	(a)	(b) 2013	(c) 2014	(d) 2015	(e) 2016	(f) 2017
1	Residential	0	0	0	0	0
2	Residential Domestic	0	0	0	0	0
3	PHEV	0	0	0	0	0
4	Commercial	1,084	1,084	1,084	1,084	1,084
5	Industrial	2,850	2,850	2,850	2,850	2,850
6	General Motors & Delphi	0	0	0	0	0
7	E-1 Economic Development	0	0	0	0	0
8	Industrial Other	2,850	2,850	2,850	2,850	2,850
9	Street Lighting	0	0	0	0	0
10	Interdepartmental	0	0	0	0	0
11	Wholesale	0	0	0	0	0
12	Total	3,935	3,935	3,935	3,935	3,935

13 Formulas:
14 Line 12 = Line 1 + Line 4 + Line 5 + Line 9 + Line 10+ Line 11
15 Line 1 = Line 2 + Line 3
16 Line 5 = Line 6 + Line 7+ Line 8

FORECAST OF FULL SERVICE DELIVERIES
(CYCLE BILLED - GWh)

Line	(a)	(b) 2013	(c) 2014	(d) 2015	(e) 2016	(f) 2017
1	Residential	12,409	12,374	12,408	12,515	12,572
2	Residential Domestic	12,393	12,349	12,376	12,476	12,503
3	PHEV	16	24	32	39	68
4	Commercial	10,587	10,607	10,623	10,823	10,928
5	Industrial	10,502	11,192	11,657	12,220	12,292
6	General Motors & Delphi	919	989	1,044	1,048	1,013
7	E-1 Economic Development	2,248	2,321	2,321	2,321	2,321
8	Industrial Other	7,335	7,882	8,292	8,851	8,957
9	Street Lighting	183	184	184	185	185
10	Interdepartmental	44	44	44	44	44
11	Wholesale	320	322	324	326	328
12	Total	34,046	34,723	35,240	36,112	36,347

13 Formulas:
14 Line 12 = Line 1 + Line 4 + Line 5 + Line 9 + Line 10 + Line 11
15 Line 1 = Line 2 + Line 3
16 Line 5 = Line 6 + Line 7 + Line 8
17 Exhibit A-19 (LDW-2) Page 3 = Exhibit A-19 (LDW-2) Page 1 - Exhibit A-19 (LDW-2) Page 2, except for Line 12

MONTHLY PEAK DEMAND FORECAST

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2013	2014	2015	2016	2017
1	January	6,006	6,163	6,262	6,264	6,324
2	February	5,817	5,972	6,059	6,101	6,152
3	March	5,632	5,790	5,875	5,927	5,988
4	April	5,291	5,441	5,529	5,605	5,667
5	May	6,265	6,409	6,482	6,623	6,701
6	June	7,530	7,680	7,765	7,906	7,983
7	July	8,127	8,277	8,362	8,489	8,567
8	August	8,344	8,488	8,528	8,614	8,656
9	September	7,002	7,151	7,234	7,372	7,447
10	October	5,861	6,020	6,110	6,162	6,222
11	November	5,858	6,014	6,102	6,127	6,185
12	December	6,161	6,321	6,412	6,435	6,494

Summer Peak (MW)

	2013	2014	2015	2016	2017
13	8,344	8,488	8,528	8,614	8,656

Winter Peak (MW)

	2013	2014	2015	2016	2017
14	6,161	6,321	6,412	6,435	6,494

MONTHLY REDUCTION IN PEAK LOAD ASSOCIATED WITH RETAIL OPEN ACCESS

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2013	2014	2015	2016	2017
1	January	477	477	480	484	481
2	February	478	478	478	455	478
3	March	490	490	485	479	479
4	April	480	475	475	486	491
5	May	526	529	551	551	526
6	June	573	571	568	568	568
7	July	560	560	560	564	564
8	August	579	581	581	577	577
9	September	574	571	571	571	573
10	October	513	513	517	522	518
11	November	533	538	534	529	529
12	December	467	460	463	464	469

Summer Peak Reduction (MW)

	2013	2014	2015	2016	2017
13	579	581	581	577	577

Winter Peak Reduction (MW)

	2013	2014	2015	2016	2017
14	467	460	463	464	469

MONTHLY PEAK LOAD TO BE SERVED BY CONSUMERS ENERGY

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2013	2014	2015	2016	2017
1	January	5,529	5,686	5,782	5,780	5,843
2	February	5,339	5,494	5,581	5,646	5,674
3	March	5,142	5,300	5,390	5,448	5,509
4	April	4,811	4,966	5,054	5,119	5,176
5	May	5,739	5,880	5,931	6,072	6,175
6	June	6,957	7,109	7,197	7,338	7,415
7	July	7,567	7,717	7,802	7,925	8,003
8	August	7,765	7,907	7,947	8,037	8,079
9	September	6,428	6,580	6,663	6,801	6,874
10	October	5,348	5,507	5,593	5,640	5,704
11	November	5,325	5,476	5,568	5,598	5,656
12	December	5,694	5,861	5,949	5,971	6,025

Summer Full Service Peak (MW)

	2013	2014	2015	2016	2017
13	7,765	7,907	7,947	8,037	8,079

Winter Full Service Peak (MW)

	2013	2014	2015	2016	2017
14	5,694	5,861	5,949	5,971	6,025

MONTHLY GENERATION REQUIREMENTS

Based on Total System Deliveries (MWh)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2013	2014	2015	2016	2017
1	January	3,510,441	3,568,378	3,621,233	3,706,471	3,742,176
2	February	3,123,180	3,180,376	3,234,130	3,406,573	3,349,761
3	March	3,256,920	3,309,725	3,359,773	3,412,990	3,473,875
4	April	3,070,223	3,134,671	3,182,638	3,256,315	3,283,303
5	May	3,223,778	3,284,840	3,330,142	3,401,986	3,428,599
6	June	3,543,713	3,605,334	3,653,073	3,728,094	3,756,953
7	July	3,877,647	3,942,897	3,987,740	4,060,694	4,088,177
8	August	3,917,643	3,981,860	4,027,065	4,100,663	4,129,551
9	September	3,345,050	3,410,325	3,458,653	3,529,042	3,555,785
10	October	3,347,180	3,408,277	3,448,805	3,511,050	3,526,045
11	November	3,181,901	3,243,527	3,285,190	3,347,809	3,363,592
12	December	3,541,090	3,601,363	3,642,018	3,706,636	3,724,394
13	Total	40,938,766	41,671,573	42,230,460	43,168,323	43,422,211

MONTHLY REDUCTION IN GENERATION REQUIREMENTS ASSOCIATED WITH RETAIL OPEN ACCESS

Based on Retail Open Access Deliveries (MWh)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2013	2014	2015	2016	2017
1	January	335,903	335,903	335,935	335,986	336,018
2	February	305,736	305,736	305,736	305,784	305,736
3	March	338,924	338,924	338,920	338,911	338,911
4	April	327,872	327,872	327,872	327,778	327,785
5	May	358,568	358,606	358,579	358,631	358,568
6	June	375,610	375,564	375,566	375,566	375,566
7	July	383,357	383,357	383,357	383,425	383,425
8	August	398,523	398,533	398,533	398,498	398,498
9	September	376,568	376,618	376,618	376,618	376,565
10	October	356,507	356,507	356,464	356,380	356,500
11	November	358,478	358,435	358,514	358,492	358,492
12	December	325,635	325,544	325,544	325,544	325,587
13	Total	4,241,681	4,241,599	4,241,638	4,241,613	4,241,651

MONTHLY GENERATION REQUIREMENTS TO BE SUPPLIED BY CONSUMERS ENERGY

Based on Full Service Deliveries (MWh)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2013	2014	2015	2016	2017
1	January	3,174,538	3,232,475	3,285,298	3,370,485	3,406,158
2	February	2,817,444	2,874,640	2,928,394	3,100,789	3,044,025
3	March	2,917,996	2,970,801	3,020,853	3,074,079	3,134,964
4	April	2,742,351	2,806,799	2,854,766	2,928,537	2,955,518
5	May	2,865,210	2,926,234	2,971,563	3,043,355	3,070,031
6	June	3,168,103	3,229,770	3,277,507	3,352,528	3,381,387
7	July	3,494,290	3,559,540	3,604,383	3,677,269	3,704,752
8	August	3,519,120	3,583,327	3,628,532	3,702,165	3,731,053
9	September	2,968,482	3,033,707	3,082,035	3,152,424	3,179,220
10	October	2,990,673	3,051,770	3,092,341	3,154,670	3,169,545
11	November	2,823,423	2,885,092	2,926,676	2,989,317	3,005,100
12	December	3,215,455	3,275,819	3,316,474	3,381,092	3,398,807
13	Total	36,697,085	37,429,974	37,988,822	38,926,710	39,180,560

MISCELLANEOUS FORECASTS

	(a)	(b)	(c)	(d)	(e)	(f)
Line		2013	2014	2015	2016	2017
1	Calendar Sales (GWh Deliveries)	37,978	38,655	39,171	40,044	40,279
2	System Efficiency (%)	92.76%	92.76%	92.76%	92.76%	92.76%
3	Generation Requirements (GWh)	40,939	41,672	42,230	43,168	43,422
4	Summer Peak (MW)	8,344	8,488	8,528	8,614	8,656
5	Annual Load Factor based on the Summer Peak (%)	56.0%	56.0%	56.5%	57.1%	57.3%

6 Note: The forecasts on this exhibit reflect the forecast of total electric deliveries before any adjustment for retail open access.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2013	))))))	Case No. U-17133

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Sharon K. Davis, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on September 28, 2012, she served an electronic copy of the Application, Testimony and Exhibits of Consumers Energy's witnesses Shawn D. Burgdorf, Natalie N. Busak, Jim K. Chilson, II, David B. Kehoe, David F. Ronk, Jr., Sara T. Walz and Lincoln D. Warriner, upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Sharon K. Davis Digitally signed by Sharon K. Davis
Date: 2012.09.28 14:50:32 -04'00'

Sharon K. Davis

Subscribed and sworn to before me this 28th day of September, 2012.

Digitally signed by Dorothy H. Wright
Date: 2012.09.28 15:11:28 -04'00'

Dorothy H. Wright, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 08/17/13
Acting in the County of Jackson

Attachment 1 to Case No. U-17133 - E-Mail Service List
Parties to Case No. U-16890

Party	Name	E-mail Address
Counsel for the Michigan Public Service Commission Staff	Spencer A. Sattler, Esq.	sattlers@michigan.gov
Counsel for Attorney General Bill Schuette	Donald E. Erickson, Esq.	ericksond@michigan.gov
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Counsel for Michigan Power Limited Partnership and Ada Cogeneration Limited Partnership	David E. S. Marvin, Esq.	dmarvin@fraserlawfirm.com
Counsel for the Association of Businesses Advocating Tariff Equity (“ABATE”)	Robert A. W. Strong, Esq. Leland R. Rosier, Esq.	rstrong@clarkhill.com lrrosier@clarkhill.com