

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Commission's own motion)
ordering **THE DETROIT EDISON COMPANY**)
to show cause why its retail rates for the sale)
and distribution of electric energy should not)
be decreased.)

Case No. U-14838

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
JAMES H. BYRON

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF JAMES H. BYRON

Line
No.

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

2 A. My name is James H. Byron. My business address is The Detroit Edison
3 Company 2000 Second Avenue, Detroit, Michigan 48226.

4

5 **Q. Can you explain your educational background?**

6 A. I received a Bachelor of Science Degree in Electrical Engineering from
7 Wayne State University in 1969. I also received a Master of Science
8 Degree in Electrical Engineering from Wayne State University in 1971.

9

10 **Q. Can you explain your professional experience?**

11 A. I began my employment in 1968 as a student in the Underground Planning
12 Division of the General Engineering Department of The Detroit Edison
13 Company ("Detroit Edison" or "Company"). This position involved assisting
14 the engineers in designing and laying out the underground cable system. I
15 was also responsible for conducting a feasibility study of converting the
16 Detroit A.C. network from 4.8 kV to 13.2 kV.

17

18 In 1969 I was employed as an Assistant Engineering Analyst in the
19 Technical Systems Planning Department where I participated in the design
20 and implementation of the engineering and management systems on the
21 computer. As an engineering analyst I assisted with or was responsible for
22 the Bulk Power Load Flow Program and data base operation, the
23 Distribution Load Flow, the Transient Stability system, the Interactive Load
24 Flow system, Short Circuit Study programs, the Unit Commitment Economic
25 Dispatch system, and various informational and engineering systems.

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1 While employed in Technical Systems, I cross-trained with the Economic
2 Studies Group of Electrical System, Data Processing Operations
3 Department, Transmission Planning Department and Bulk Power
4 Transactions. These cross-training assignments spanned approximately a
5 four-year period. I also served on the Automatic Meter Reading Task Force.

6
7 In 1976 I joined Bulk Power Transactions as a senior engineer. As a senior
8 engineer, I worked on the Monroe Unit No. 2, the Trenton Channel Unit No.
9 8 and the River Rouge Unit No. 2 Insurance Studies, Time of Day studies,
10 Load Management applications of water heater controls, studies of other
11 load management techniques, Purchased Power and Net Interchange
12 forecasts, fuel forecasts and dispatch fuel costs, coal conservation dispatch,
13 and coordinating informational and engineering systems with various areas
14 of the Company.

15
16 During the summer of 1977 I was assigned to the Michigan Electric Power
17 Coordination Center and worked in the operations group. In June 1980 I
18 was promoted to the position of Interconnection Agreements Engineer. In
19 connection with a temporary assignment in the fall of 1983, I assisted the
20 outage manager on the Monroe Unit No. 1 scheduled outage. In April 1987,
21 I was promoted to the position of Senior Interconnection Agreements
22 Engineer. In December 1990, I was promoted to the position of Director -
23 Operations in Power Supply Transactions.

24
25 In February of 1996 a new organization was created by transferring and
26 integrating Power Supply Transactions and the large customer marketing

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1 and sales group from the Energy Marketing & Distribution Organization.
2 The title of the new organization was Customer Energy Solutions (CES). In
3 July 1996, I was appointed Director of Sourcing with the added
4 responsibility for long term resource planning.
5

6 **Q. What were your responsibilities in this position?**

7 A. As Director of Sourcing, I was responsible for the negotiation, development
8 and administration of interconnection operating agreements with other utility
9 systems. I supervised the purchasing and selling of weekly, seasonal, and
10 longer term power from interconnection transactions, the forecasting of
11 purchased power and system operation, the analysis of long term resource
12 requirements, the preparation of testimony with respect to both forecast and
13 actual purchased power and system operation, the developing and filing of
14 interconnection agreements and rates with the Federal Energy Regulatory
15 Commission ("FERC"), the preparation of bills for the smaller utility systems
16 in Michigan, and the interaction with other operating departments to
17 maintain and improve overall system economics and adequacy of power
18 supply. Additionally, I was responsible for preparation of billing data for
19 qualified facilities selling energy to the Company. I also served on
20 administrative and/or operating committees and subcommittees established
21 with other utilities.
22

23 In December of 1996, I was appointed Director of Energy Management -
24 Customer Energy Solutions. My duties included developing energy
25 management services for our customers, negotiating and administering
26 contracts, providing technical expertise of system operations for the

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1 Company, and representing the Company on various inter-company
2 committees.

3

4 In November of 1997, I was appointed Director of Planning & Optimization –
5 Operation, Planning, and Control. The title of the organization was changed
6 and my title became Director - Economic Operation of Power Planning &
7 Optimization. In June 1999, a new organization, Generation Optimization
8 was formed but my title and position were unchanged. My responsibilities
9 were negotiation, development and administration of interconnection
10 operating agreements with other utility systems. I supervised the
11 purchasing and selling of weekly, seasonal, and longer term power from
12 interconnection transactions, the forecasting of purchased power and
13 system operation, the analysis of long term resource requirements, the
14 preparation of testimony with respect to both forecast and actual purchased
15 power and system operation, the developing and filing of interconnection
16 agreements and rates with the FERC, and the interaction with other
17 operating departments to maintain and improve overall system economics
18 and adequacy of power supply. I also served on administrative and/or
19 operating committees and subcommittees established with other utilities.

20

21 In April 2001, I was appointed Manager of Generation Optimization-Power
22 Supply Planning. My main areas of responsibility were to: (1) direct the
23 planning for generation capacity and purchase power needs; (2) direct the
24 development of load and sales forecasts for the Company; (3) direct the
25 establishment of supply reliability policies that ensure continued supply
26 reliability at the least possible cost; and (4) participate in regulatory

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1 proceedings on behalf of the Company regarding matters involving power
2 purchases and sales and other supply related issues.

3

4 **Q. What is your current position?**

5 A. In November 2002, Generation Optimization was re-organized and the
6 responsibility for load forecasting was moved to the Controllers
7 organization. Currently, I continue to be Manger of Generation
8 Optimization-Power Supply Planning, retitled Manager of Generation
9 Optimization-Power Planning & Reliability, and my main areas of
10 responsibility are to: (1) direct the planning for generation capacity and
11 purchase power needs including transmission requirements; (2) direct the
12 negotiation, development and administration of interconnection operating
13 agreements with other utility systems; (3) direct the purchasing and selling
14 of weekly, seasonal, and longer term power ; (4) direct the establishment of
15 supply reliability policies that ensure continued supply reliability at the least
16 possible cost; and (5) participate in regulatory proceedings on behalf of the
17 Company regarding matters involving power purchases and sales, system
18 operations, and other power supply-related issues.

19

20 **Q. Have you previously testified before the Commission?**

21 A. Yes. I testified before the Michigan Public Service Commission ("MPSC") in
22 27 monthly Purchased and Net Interchange Power Adjustment cases during
23 the period 1978 through 1982, and in the following additional cases:

24 U-6488-R 1982 Fuel and Purchased and Net Interchange Power
25 Adjustment Clause Reconciliation

26 U-7550 1983 Power Supply Cost Recovery Plan

Line No.			
1	U-7775	1984	Power Supply Cost Recovery Plan
2	U-7775-R	1984	Power Supply Cost Recovery Reconciliation
3	U-8020	1985	Power Supply Cost Recovery Plan
4	U-8020-R	1985	Power Supply Cost Recovery Reconciliation
5	U-8291	1986	Power Supply Cost Recovery Plan
6	U-8291-R	1986	Power Supply Cost Recovery Reconciliation
7	U-8578	1987	Power Supply Cost Recovery Plan
8	U-8789	1987	Main Electric Rate Case
9	U-8880	1988	Power Supply Cost Recovery Plan
10	U-8869-DE/	1991	Establishing a Framework for Future Capacity
11	U-9798		Solicitations from Qualifying Facilities
12	U-10102	1994	Main Electric Rate Case
13	U-10103	1993	Power Supply Cost Recovery Plan
14	U-10103-R	1993	Power Supply Cost Recovery Reconciliation
15	U-10427	1994	Power Supply Cost Recovery Plan
16	U-10427-R	1994	Power Supply Cost Recovery Reconciliation
17	U-10702	1995	Power Supply Cost Recovery Plan
18	U-10965-R	1996	Power Supply Cost Recovery Reconciliation
19	U-11175	1997	Power Supply Cost Recovery Plan
20	U-11175-R	1997	Power Supply Cost Recovery Reconciliation
21	U-11528	1998	Power Supply Cost Recovery Plan
22	U-11528-R	1998	Power Supply Cost Recovery Reconciliation
23	U-11726	1998	Accounting Authority Related to the Accelerated
24			Amortization of the Fermi 2 Nuclear Plant
25	U-11800	1999	Power Supply Cost Recovery Plan
26	U-12121	2000	Power Supply Cost Recovery Plan

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1	U-12639		Implementation of the Provisions of Section
2			10a(10) of 2000 PA 141
3	U-13350	2000-2001	Implementation of the Stranded Cost Recovery
4			Procedure and For Approval of Net Stranded
5			Cost Recovery Charges
6	U-13808	2003	Main Case & 2004 Power Supply Cost Recovery
7			Plan
8	U-13808-R	2004	Power Supply Cost Recovery Reconciliation
9	U-14474	2004	Implementation of the Commission's Final Order
10			in Case No. U-13808 Concerning Inter Alia, 2004
11			Net Stranded Costs
12	U-14275	2005	Power Supply Cost Recovery Plan
13	U-14275-R	2005	Power Supply Cost Recovery Reconciliation
14			(Testimony Filed March 30, 2006)
15	U-14702	2006	Power Supply Cost Recovery Plan
16			
17	I have also testified before the FERC in the following cases:		
18	EL02-111		FERC Investigation of the Rates For Through and
19			Out Service under the Midwest ISO and PJM
20			Tariffs
21	ER04-691/EL04-104		Midwest Independent System Operator, Inc.
22			Public Utilities With Grandfathered Agreements in
23			the Midwest ISO Region
24			.

THE DETROIT EDISON COMPANY
DIRECT TESTIMONY OF JAMES H. BYRON

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1 **Q. What is the purpose of your testimony?**

2 A. The purpose of my testimony is to present Detroit Edison's current long range
3 resource plan and the projections of Detroit Edison power generation and
4 purchased and net interchange power ("PNI") requirements and associated
5 expenses, transmission requirement and expense, regulated emissions and
6 associated allowance expense, and generation capacity factors. The system
7 generation and PNI projections I am presenting are for electric requirements
8 only and do not include industrial send-out steam. My testimony will address
9 2005 actual expenses and projected expenses covering 2006 - 2011.

10

11 **Q. Which Exhibits are you supporting?**

12 A. I am supporting information on the following Exhibits:

13 Exhibit DE-6

14 Schedule F1 Planned Long Range Generation Changes

15 Exhibit DE-16

16 Schedule F2 Summer Peak Loads & Capabilities

17 Schedule F7 Purchased and Net Interchange Power and Expenses,
18 2005 - 2011

19 Schedule F8 Power Plant Generation, Fuel Expense, and Emission
20 Allowance Expense, 2005 - 2011

21 Schedule F9 Generation Capacity Factor, 2005 - 2011

22 Schedule F11 Projected Fuel, Emission Allowance, Net Purchased
23 Power, and Transmission Expense, 2005 – 2011

24

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1 **Q. How is your testimony organized?**

2 A. My testimony consists of the following two (2) parts:

3 Part I Detroit Edison's Long Range Resource Plan

4 Part II Detroit Edison's Projections of Power Generation, Capacity
5 Factors, Purchased and Net Interchange Power, Transmission
6 Requirements and Expense, Regulated Emissions and
7 Allowance Expense and Mitigation Adjustment

8

9 **Part I**

10 **Detroit Edison's Long Range Resource Plan**

11

12 **Q. What is the net demonstrated summer operating capability of the**
13 **Company's generation resources?**

14 A. As of January 1, 2006 the Company's total owned summer capability was
15 11,113 MW. Of the Company's net demonstrated summer capability, 7,983
16 MW is from fossil steam plants, 1,111 MW from the Fermi 2 nuclear plant, 917
17 MW from the Ludington Pumped Storage Hydroelectric ("Ludington") facility,
18 and 1,102 MW from peakers. The Company also has contracted for 83 MW
19 from Qualified Facilities. Therefore, the total summer owned and
20 purchased capacity available is 11,196 MW.

21 The Michigan Public Power Agency ("MPPA") is a joint owner of the Belle
22 River Power Plant. Its ownership entitlement is effectively 18.61% of the
23 capability of the plant (MPPA thus controls 234 MW of the Belle River Power
24 Plant). MPPA's ownership of Belle River is not included in the 11,113 MW of

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1 the Company's owned capability.

2

3 **Q. Can you explain Schedule F1 of Exhibit DE-6?**

4 A. Schedule F1 of Exhibit DE-6 is the implementation schedule for changes to
5 the generation resources owned by Detroit Edison for the years 2005 – 2011.

6 The changes reflect the upgrade in capability by 35 MW of Conners Creek in
7 2006. The changes also reflect the installation of scrubbers on Monroe unit 3
8 in the spring of 2009, Monroe unit 4 in the fall of 2008, Monroe unit 1 in the
9 spring of 2010, and on Monroe unit 2 in the fall of 2010, each of which
10 reduces the capability by 10 MW on each unit, as discussed in the testimony
11 of Mr. Guy Harris. There will also be an increase in capacity at Fermi 2 in 2006
12 by 4 MW and by 66 MW in 2011 as discussed by Mr. Colonnello. As shown
13 on this Schedule, Detroit Edison's net generation resource capacity increases
14 by 65 MW through 2011. No other capacity increases between 2005 and
15 2011 are currently planned. However, the Company is actively participating in
16 discussions on developing Michigan's 21st Century Energy Plan.

17

18 **Q. What major changes to the Company's net demonstrated operating**
19 **capability have occurred since 2004?**

20 A. The major changes to the Company's summer net demonstrated operating
21 capability since 2004 were the installation of the dense pack low and high
22 pressure turbines on Monroe units 2 and 3, which increased the summer net
23 demonstrated capacity of the units by 35 MW each.

24

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1 **Q. Can you explain Schedule F2 of Exhibit DE-16?**

2 A. Schedule F2 of Exhibit DE-16 is the long range resource plan of the
3 Company to supply its summer full service (aka bundled) customer adjusted
4 peak demand with generation resources available to Detroit Edison
5 supplemented with additional summer purchased power as required for the
6 years 2005 (actual) and 2006 through 2011. This long-range resource plan
7 is based on the Company's latest load forecast as presented in the
8 testimony and exhibits of Dr. Aldo Colandrea, the current net demonstrated
9 summer operating capability of Detroit Edison's owned generation
10 resources, the planned changes in capacity as shown on Schedule F1 of
11 Exhibit DE-6, and the long-term purchased capacity that is under contract to
12 the Company.

13

14 **Q. What is the Adjusted Peak Demand?**

15 A. The Adjusted Peak Demand is the forecasted full service customers' peak
16 demand adjusted for the forecasted demand of the customers electing
17 service under special contracts or tariff rates R-10, LCC, D-8, and the
18 interruptible service to the FERC wholesale for resale customers.

19

20 **Q. Why is this adjustment made to the bundled peak demand forecast?**

21 A. This adjustment is made because the Company is not planning on acquiring
22 long-term resources; either installed generation or purchased power to
23 supply this demand. This is consistent with the Summer Capacity Plans
24 that were filed by Detroit Edison with the MPSC and with the projections

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1 presented in the Power Supply Cost Recovery ("PSCR") Plan cases for the
2 years 1998, 1999, 2000, 2004, 2005 and 2006 and in the Main Electric Rate
3 Case No. U-13808.

4

5 **Q. Does the Company plan on interrupting the interruptible tariff customers**
6 **at time of peak?**

7 A. No. The Company will attempt to serve this load from available generation
8 resources or from the wholesale electric power market. If power is not
9 available, then these customers would be required to curtail/interrupt their
10 load in compliance with the Company's tariffs.

11

12 The FERC wholesale for resale customers have generation available if their
13 interruptible supply is curtailed.

14

15 **Q. Will the demand of the interruptible air conditioning customers be**
16 **treated in the same manner?**

17 A. No. Interruptible air conditioning ("IAC") is being treated consistent with the
18 summer planning criteria as described in the 1998, 1999, 2004, 2005 and
19 2006 PSCR Plan cases and in the 2003 Main Electric Rate Case No. U-
20 13808. We believe that this planning criteria has been accepted by the
21 MPSC.

22

23 The table that follows compares the relevant features of the IAC and R-10
24 rates as taken from the Company's schedule of rates (MPSC No. 9).

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1

	R-10 (Inc. Int. LCC)	D1.1 (IAC)
Subject to PSCR Clause	No	YES
Price Includes	Incremental cost of fuel and purchased power.	Average cost of fuel and purchased power
Benefits	Significant price reduction Provision for Buy through	Small price reduction, approximately \$25 per year No Buy through
Return to firm service after:	5-year notice	3-day notice

2

3 As shown, the rates are very different.

4

5 The Company's plan is premised on planning to serve the IAC load, and
6 similar interruptible load, but to use these interruptible tariffs as the
7 operating tool they were intended to be. That is, they represent load that
8 can be interrupted for contingencies on peak load days. However, the
9 Company does not plan on providing reserves above IAC forecasted
10 demand.

11 At the same time, planning to serve this load produces the secondary
12 benefits of providing operating reserve in lieu of purchases and also allows
13 the Company to cycle the interruptible equipment occasionally to make a
14 sale when market prices are sufficiently high.

15

16 **Q. What is a reserve margin?**

17 A. A reserve margin is defined as the difference between available resources

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1 and peak demand, divided by the peak demand and expressed as a
2 percentage. Reserves above the peak demand are required due to the
3 uncertainties and contingencies associated with (1) weather and load
4 forecasts, (2) generating unit operation, (3) transmission availability and
5 constraints, and (4) the reliability of external power.

6

7 It has been the Company's experience and past practice that a minimum
8 planning reserve margin of 15% is required to ensure reliability due to these
9 uncertainties. The 15% planning reserve margin is consistent with the
10 Company's resource planning requirements as used in the previous main
11 electric rate cases Nos. U-10102 and U-13808, past PSCR Plan cases and
12 the Summer Capacity Plans that were filed by Detroit Edison with the
13 MPSC.

14

15 **Q. How were the planned reserve margins shown on Schedule F2**
16 **developed?**

17 A. The reserve margins were calculated as 15% of the adjusted peak demand
18 minus 38 MW, which represents reserves not required for the IAC, plus 4%
19 of the Electric Choice peak demand for operating reserve that transmission
20 customers must provide. If the transmission customer does not self provide
21 or purchase these reserves from other generating sources, the Company
22 provides this additional reserve.

23

24 **Q. What are the total resources required?**

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1 A. The total resources required are the sum of the adjusted peak demand and
2 the planned reserve margin. This is the amount of resources, installed
3 available generation and purchased power, required to ensure adequate
4 supply to serve the forecasted peak demand.

5

6 **Q. What is the available summer operating capability of the Company's**
7 **owned generation?**

8 A. As previously described, the current summer net demonstrated operating
9 capability of the Company's owned generation is 11,113 MW. This includes
10 84 MW of generation from the Marysville Power Plant. However, the
11 decision has been made to hold Marysville in a cold standby status
12 condition. With Marysville Power Plant in cold standby status and the
13 upgrades of Conners Creek and Fermi 2, the Company's 2006 summer
14 available operating capability is 11,068 MW.

15

16 **Q. What does the long term purchased capacity shown on Schedule F2**
17 **represent?**

18 A. The long term purchased capacity of 83 MW shown on Schedule F2 is the
19 projected purchased energy and capacity from PURPA Qualifying Facilities
20 ("QF") that the Company is obligated to purchase under sections 201 and 210
21 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Included are
22 the projections of energy and capacity from waste-to-energy facilities under
23 existing contracts as specified in 1989 Public Act 2 ("PA 2").

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1 The Michigan Public Service Commission ("MPSC") has approved the
 2 contracts for purchases from the following waste to energy facilities covered
 3 by PA 2:

4

5	<u>Facility</u>	<u>Case</u>	<u>Approved</u>
6	Greater Detroit Resource Recovery	U-10066	8/14/92
7	Riverview Energy Systems	U-10068	8/14/92
8	Amended	U-10879	9/21/95
9	Sumpter Energy Associates (Station #1)	U-10069	8/14/92
10	Amended	U-10879	9/21/95
11	Wayne Energy Recovery	U-10070	8/14/92
12	Lyon Electric Generating	U-10232	2/23/93
13	Amended	U-10879	9/21/95
14	Turbine Power Limited Partnership - Arbor Hills	U-10594	8/03/94
15	Amended	U-10879	9/21/95
16	Ann Arbor	U-10879	9/21/95

17

18 **Q. What is the additional summer capacity requirement?**

19 A. The additional summer capacity requirement is the forecasted amount of
 20 capacity needed to be acquired in order to achieve the amount of total
 21 resources required to serve the forecasted adjusted bundled customer peak
 22 demand. The Company currently anticipates purchasing this power
 23 seasonally from the wholesale electric power market.

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1 With the passage of the Energy Policy Act of 1992, independent power
2 producers ("IPP") and exempt wholesale generators have built merchant
3 power plants to supply wholesale power to electric utilities and sell into the
4 wholesale electric market or self supply. At this time, forecasting to
5 seasonally purchase power from the wholesale power market is the
6 economic and prudent decision given the uncertainties regarding the
7 amount of Electric Choice load, market prices, and the results of the
8 Michigan 21st Century Energy Plan.

9

10

Part II

11

Detroit Edison's Projections of Power Generation, Capacity Factors,

12

Purchased and Net Interchange Power, Transmission Requirement and

13

Expense, and Regulated Emissions and Allowance Expense

14

15 **Q. How were the projections of the power generation and purchased and**
16 **net interchange power developed?**

17 A. These projections were developed utilizing the PROMOD IV System
18 computer software that simulates the operation of an electric utility power
19 system. The program requires as input, the Net System Output ("NSO")
20 forecast, the unit capabilities, the projected periodic maintenance schedule,
21 the projected availabilities of the units, the projected generation of Fermi 2,
22 dispatch fuel costs, variable O & M, the projection of energy purchased from
23 PURPA QF's, projections of wholesale electric power market prices, and
24 projections of prices for emission allowances for sulfur dioxide ("SO₂"),

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1 oxides of nitrogen (“NO_x”) and mercury (“Hg”).

2

3 The reasonableness of the projection was evaluated based on historical
4 operation and expected changes due to maintenance schedules, unit
5 performance and changes in NSO. The forecasted NSO is for the “full
6 service” load customers who are served by Detroit Edison generating
7 resources and third party wholesale power sales, the forecasted NSO does
8 not include Electric Choice customer load served by Alternative Electric
9 Suppliers (“AESs”).

10

11 The projections are for the Company’s generating resources and do not
12 include MPPA’s generation from Belle River.

13

14 **Q. How does the Belle River sale relate to system operation and PNI?**

15 A. The MPPA has purchased 37.22% of Unit 1 and 18.61% of the common
16 facilities of the Belle River Power Plant and is contractually entitled to 18.61%
17 of the total plant output. The buy back provision of the agreement ended in
18 1994 and MPPA is now expected to take 100 percent of their entitlement of
19 Belle River generation.

20

21 The Company has also agreed to provide back-up capacity and energy, if
22 requested by MPPA, when either Belle River Unit 1, Belle River Unit 2, or
23 both, are totally or partially out of service due to forced outages, unforeseen
24 maintenance, temporary derates, scheduled maintenance, plant modifications,

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1 or environmental constraints for which the Company has planned plant
2 modifications. MPPA has been exercising its right to schedule replacement
3 power from other sources and, as a result, the amount of back-up power
4 provided by the Company has been minimal and is therefore not included in
5 our projections.

6

7 **Q. Is the methodology used to develop the information for the projections**
8 **similar to that used in previous filings with the MPSC?**

9 A. Yes. The methodology is largely the same as that used in the Main Electric
10 Rate Case No. U-13808 and in the 2005 and 2006 Power Supply Cost
11 Recovery Plan Case Nos. U-14275 and U-14702. In this modeling, the
12 wholesale hourly power market is developed from the wholesale forward
13 power market prices. This modeling accommodates both purchasing and
14 selling to the market on an hourly basis and provides a better reflection of the
15 wholesale power market. The modeling also includes the regulated emissions
16 projection from the Company's power plants.

17

18 **Q. What is the Company's emission reduction strategy?**

19 A. As described by Mr. Skiles Boyd, the Company has chosen to employ a
20 strategy which combines the installation of technology-based equipment
21 with the purchase of emission allowances from the market when required.

22

23 **Q. Can you explain Exhibit DE-16, Schedule F7-1?**

24 A. Yes. Exhibit DE-16, Schedule F7-1 is the actual and projected purchases of

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1 power and energy for the years 2005 (actual) through 2011.

2

3 **Q. Can you explain the various types of purchase transactions shown on**
4 **Exhibit DE-16, Schedule F7-1?**

5 A. Yes. The types of purchase transactions shown on this Schedule are
6 Wholesale Market purchases including the Midwest Independent
7 Transmission System Operator ("MISO") Energy Market, Summer Contracts,
8 Summer Calls, and PURPA Qualified Facilities.

9

10 "Wholesale Market" is a projection of the weekly, daily and hourly purchases
11 from wholesale market suppliers. Wholesale market suppliers include
12 traditional utilities such as Consumers Energy and American Electric Power
13 ("AEP"), independent power producers, and purchases from the MISO Energy
14 Market and the Independent Electricity System Operator ("IESO") energy
15 market in Ontario. These purchases are made for reliability and as economic
16 alternatives to running the Company's own generation.

17

18 Summer Contracts are that portion of the summer capacity purchases
19 estimated to be procured as "5x16" standard contracts for this projection.

20

21 Summer Calls are the portion of the estimated summer capacity purchases
22 estimated to be procured as call options, which could be a standard "1x16"
23 day ahead call option or a product which can be called intraday for some
24 minimum number of hours. Included as part of the summer calls are the

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1 capacity only purchases that the Company can include as capacity resources
2 to meet its capacity obligation but do not include energy.

3

4 The "Additional Summer Capacity Requirement" shown on Exhibit DE-16,
5 Schedule F2 column (m), is the amount of capacity that the Company
6 purchased or plans to purchase under the Summer Contracts and Summer
7 Calls for reliability. Additional power may also be purchased in the summer
8 based on economics.

9

10 PURPA Qualifying Facilities are the projections of energy and capacity that
11 the Company is obligated to purchase under sections 201 and 210 of the
12 PURPA. Included are the projections of energy and capacity from waste-to-
13 energy facilities under existing contracts as specified in PA 2.

14

15 **Q. How were energy amounts and expenses for the economy purchases**
16 **from "Wholesale Market" developed?**

17 A. The economy purchases from the Wholesale Market were modeled in
18 PROMOD based on projections of the wholesale electric market. The forward
19 market curve for the Michigan Hub represents our best estimate of forward
20 market prices as of the close of business on March 31, 2006. The forward
21 market curve is for the Michigan Hub.

22

23 **Q. How did you develop the capacity and energy amounts and expenses**
24 **for the Summer Contracts and Summer Purchases?**

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1 A. The total summer capacity to be purchased is shown on Exhibit DE-16,
2 Schedule F2. For 2007, capacity purchases of 2,325 MW are projected to be
3 required, all of which are projected as call options. The call options assumed
4 for June through August involve a mix of products, with premium costs ranging
5 from \$3.4/kW-Month to \$7.2/kW-Month and strike prices between \$85/MWh
6 and \$115/MWh. Also, 250 MW of capacity-only call options were projected
7 with a premium cost of \$1.4/kW-Month. This mix represents a reasonable
8 estimate of the types of products needed to match the Detroit Edison load
9 shape, and the types of products expected to be available in the marketplace
10 based on recent experience. The final mix of "5x16" contracts and call
11 options, and the types of call option products that will actually be procured will
12 be dependent on the actual market prices and the types of products that are
13 actually available during the procurement process.

14

15 The cost of the summer contracts was derived from the Michigan Hub forward
16 market curve. A "capacity" adder was applied to the forward curve values to
17 capture the increased price typically paid for actual "physical" power products.

18

19 The summer call energy prices were developed using the underlying prices
20 from the forward wholesale energy market curve, natural gas projections and
21 the historic information.

22

23 **Q. What is meant by the term energy imbalance and how does it impact**
24 **Detroit Edison?**

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1 A. Energy imbalance was a transmission ancillary service that the Company
2 purchased and sold to the transmission provider and Alternative Electric
3 Suppliers participating in Electric Choice. The energy imbalance is the
4 difference between actual load (or generation) and the scheduled load (or
5 generation). The Company purchased or sold energy imbalance under the
6 terms of the FERC transmission tariff. Since the start of the MISO energy
7 Market, energy imbalance is no longer provided by the Company and is
8 completely supported by MISO through the market process.

9

10 **Q. Has the Company entered into capacity transaction purchases**
11 **exceeding six months?**

12 A. Yes. The Company has entered into capacity purchases exceeding six
13 months from co-generators and qualified small power producers as specified
14 by PURPA, and from waste-to-energy facilities under existing contracts
15 specified in 1989 PA 2. The Commission has approved these purchases, as
16 has been previously discussed.

17

18 **Q. What are the MISO Energy Market costs?**

19 A. The MISO Energy Market costs are the expenses the Company incurs as a
20 MISO market participant. Mr. Shields describes these expenses and
21 supports the expense projections shown on Exhibit DE-16, Schedule F7-4.

22

23 **Q. Can you explain Exhibit DE-16, Schedule F7-2?**

24 A. Yes. Exhibit DE-16, Schedule F7-2, is the actual (2005) and projected

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1 (2006 – 2011) sales of interconnected power and energy to the wholesale
2 market including the MISO Energy Market. The Energy Imbalance Credit for
3 2005 represents the average fuel cost of making the energy imbalance
4 sales.

5

6 **Q. Can you explain how the sales to the wholesale market were developed?**

7 A. Yes. Sales to the wholesale market include the annual projected third party
8 sales and those opportunistic sales made to third parties at the wholesale
9 level on those occasions when Detroit Edison has excess power available
10 that is below the assumed Michigan Hub energy market price. A
11 representation of the forward wholesale market price curve is input to
12 PROMOD as a proxy to represent the market price.

13

14 **Q. Can you explain Exhibit DE-16, Schedule F7-3?**

15 A. Yes. Exhibit DE-16, Schedule F7-3, is the actual (2005) and projected
16 purchased and net interchange (PNI) power for the years 2006 through
17 2011. The interconnected purchases are as shown on Exhibit DE-16,
18 Schedule F7-1 and the sales are as shown on Schedule F7-2.

19

20 **Q. Can you describe Exhibit DE-16, Schedules F8-1 through F8-7?**

21 A. Yes. Exhibit DE-16, Schedule F8-1 shows the year 2005 actual electric
22 generation and fuel expense incurred by the Company. Exhibit DE-16,
23 Schedules F8-2 through F8-7 shows the projected electric generation and
24 fuel expense by Detroit Edison plant for the year. Shown for each plant are

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1 the primary fuel type, the annual generation, the total unit fuel price
2 expressed as cents per million BTU (¢/MBTU), the fuel cost expressed as
3 dollars per megawatt hour (\$/MWh), and the fuel expense in thousands of
4 dollars.

5

6 I am supporting the annual generation and fuel cost for all plants except
7 Fermi 2. Mr. Wayne Colonnello developed the Fermi 2 information as shown
8 on Exhibit DE-16, Schedule F5-1. The total unit fuel price and fuel expense
9 for Detroit Edison's fossil-fueled plants are supported by Mr. Gary
10 Lapplander and Mr. Wayne Colonnello supports similar information for
11 Fermi 2.

12

13 **Q. How were the annual projections of generation for each plant**
14 **determined?**

15 A. As previously discussed, the projections for generation and purchased power
16 were developed utilizing PROMOD IV, which is a production cost simulation
17 computer program. The program simulates the economic dispatch of the
18 resources available to develop the generation projections, fuel consumption
19 requirements and tons of emissions. The heat requirements associated with
20 the fuel consumption are then utilized by Mr. Gary Lapplander to develop unit
21 fuel cost and fuel expense.

22

23 **Q. What does Exhibit DE-16, Schedules F8-8 contain?**

24 A. Exhibit DE-16, Schedule F8-8 displays the Company's projection of NO_x

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1 emission allowance expense for the years 2006 through 2011. Also shown
2 is the actual NO_x emission allowance expense incurred in 2005. The actual
3 average cost of NO_x emission allowances purchased by the Company
4 though 2005 was \$2,725/ton. The market price in 2004-2005 ranged from
5 approximately \$2,000/ton to \$3,500/ton. The market prices of NO_x emission
6 allowances since 1999 has ranged from below \$1,000/ton to over
7 \$7,000/ton.

8

9 Shown on Exhibit DE-16, Schedule F8-8, page 1 of 2, is the following
10 information for the ozone season (May – September) projected tons and
11 costs of the allowances: (1) the beginning balance of the Company's
12 allowances, (2) the allowances allocated to the Company, (3) allowances
13 purchased by the Company, (4) the expected allowances to be consumed,
14 (5) the ending balance of the allowances and (6) the net expense of the
15 allowances consumed for the relevant years. Page 2 of 2 of this exhibit
16 displays the annual NO_x emission allowance projections. Under the Clean
17 Air Interstate Rule, beginning in 2009, there will be separate compliance
18 requirements for the ozone season and annual NO_x emissions.

19

20 **Q. Can you explain, in general terms, the Clean Air Interstate Rule?**

21 A. Yes, On March 10, 2005, the Environmental Protection Agency ("EPA")
22 finalized the Clean Air Interstate Rule ("CAIR"). Through the use of a cap-
23 and-trade approach, the CAIR objective is to achieve substantial reductions
24 of sulfur dioxide (SO₂) and oxides of nitrogen (NO_x) emissions. CAIR

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1 covers 28 eastern states (including Michigan) and the District of Columbia.

2

3 States must achieve the required emission reductions using one of two
4 compliance options: 1) meet the state's emission budget by requiring power
5 plants to participate in an EPA-administered interstate cap-and-trade
6 system that caps emissions in two stages, or 2) meet an individual state
7 emissions budget through measures of the state's choosing.

8

9 CAIR provides a Federal framework requiring states to substantially reduce
10 emissions of SO₂ and NO_x. The EPA anticipates that states will achieve
11 this primarily by reducing emissions from the power generation sector.

12

13 The Clean Air Interstate Rule establishes a cap-and-trade system for SO₂
14 and NO_x emission allowances using the EPA's Acid Rain Program as a
15 model. Under the cap-and-trade approach in CAIR, EPA will allocate
16 emission "allowances" for SO₂ and NO_x to each state. The states will
17 distribute those allowances to affected sources, which can trade them. As a
18 result, sources will be able to choose from many compliance alternatives
19 including: installing pollution control equipment; switching fuels; or buying
20 excess allowances from other sources that have reduced their emissions.
21 Because each source must hold sufficient allowances to cover its emissions
22 each year, the limited number of allowances available ensures required
23 emission reductions are achieved.

24

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1 If states choose to meet their emissions reductions requirements by
2 controlling power plant emissions through an interstate cap-and-trade
3 program, at full implementation, CAIR will reduce power plant SO₂
4 emissions in affected states to just 2.5 million tons, 73% below 2003
5 emissions levels. The State of Michigan SO₂ emissions budget would be
6 178,605 tons for 2010 – 2014. The State's annual budget would be 125,024
7 tons in 2015 and beyond.

8
9 The regional annual SO₂ emissions budget represents the total cap level for
10 SO₂ emissions for the region. The calculated regional budget applies
11 specially-designed allowance retirement ratios to existing Acid Rain
12 Program allowances under CAIR beginning in 2010, (2:1), and increasing in
13 2015 and beyond (2.86:1). These ratios were developed to cut the
14 allowance emission levels by half beginning in 2010 and 65 percent
15 beginning in 2015.

16
17 CAIR also will achieve significant NO_x emission reductions across states
18 covered by the rule. Since NO_x emissions contribute to the formation of
19 both fine particles and ground level ozone, separate NO_x emissions budgets
20 are created for annual and ozone season NO_x emissions. In 2009, CAIR
21 will reduce NO_x emissions by 1.7 million tons or 53% from 2003 levels. In
22 2015, CAIR will reduce power plant NO_x emissions by 2 million tons,
23 achieving a regional emissions level of 1.3 million tons, a 61% reduction
24 from 2003 levels. The State of Michigan would have an annual NO_x

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1 emissions budget of 65,304 tons and an ozone season budget of 28,971
2 tons for 2009 – 2014. The State's annual budget would be 54,420 tons and
3 the seasonal budget would be 24,142 tons in 2015 and beyond.

4

5 Within the trading program, the NO_x emissions budgets represent the
6 number of allowances a State receives and may allocate. There will be
7 separate trading programs and separate emission allowances for the annual
8 and seasonal CAIR programs. Annual NO_x emissions allowances are
9 eligible for compliance with annual emissions only and cannot be used for
10 ozone-season compliance. Similarly, seasonal allowances are eligible for
11 ozone-season (May through September) compliance only. Banked NO_x
12 State Implementation Plan (SIP) Call allowances may only be used for
13 compliance in the CAIR ozone-season program.

14

15 **Q. What is the flow control component of the NO_x emission projection?**

16 A. The flow control component of the NO_x emission projection is developed
17 based on the flow control provision of the NO_x emission trading program.
18 The flow control provisions were designed to discourage extensive use of
19 banked allowances in a particular ozone season. The flow control will be
20 triggered if the total number of banked NO_x emission allowances from all
21 sources exceeds 10% of the region-wide NO_x emissions budget.

22

23 After completing compliance deductions for an ozone season, the EPA will
24 tabulate the total number of banked NO_x emission allowances. If the total
25 bank is less than 10% of the regional trading budget, then no flow control

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1 will apply in the following season. If the total bank is greater than 10% of
2 the regional trading budget, then the EPA will calculate a flow control ratio.
3 This ratio will indicate what percentage of the banked allowances can be
4 used with no discount for compliance in the following ozone season ("1 for
5 1") and what percentage of banked allowances, if used, must be discounted
6 and deducted at a rate of two allowances for each ton of emissions ("2 for
7 1"). The flow control ratio is recalculated each year after the compliance is
8 completed. For the NO_x emission projection, a flow control ratio of 0.27 was
9 used for 2006, 0.28 for 2007, and 0.29 for 2008.

10

11 **Q. Can you explain Exhibit DE-16, Schedule F8-9?**

12 A. Yes. Exhibit DE-16, Schedule F8-9 is the Company's 2005 actual and 2006
13 - 2011 projection of SO₂ emission allowance expense. Shown on Exhibit
14 DE-16, Schedule F8-9 is the following information for the projected tons and
15 costs of the allowances: (1) the beginning balance of the Company's
16 allowances, (2) the allowances allocated to the Company, (3) allowances
17 purchased by the Company, (4) the expected allowances to be consumed,
18 (5) the ending balance of the allowances and (6) the net expense of the
19 allowances consumed for the relevant years.

20

21 **Q. Why is Detroit Edison requesting that the SO₂ emission allowance**
22 **related costs be recovered in the PSCR process?**

23 A. One primary generation alternative to utilizing SO₂ emission allowances
24 over and above the allocated level of allowances to meet the Clean Air Act

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1 requirements would be to burn lower sulfur, but more expensive, coals. In
2 fact, lower sulfur, but higher priced, coal can be utilized to reduce the need
3 to purchase emission allowances and therefore, the total cost of compliance
4 would be recovered through the PSCR mechanism. While there are some
5 practical limitations, as I discuss later, to the Company's fuel blending
6 capabilities, it is theoretically possible that additional fuel blending could be
7 utilized to avoid some SO₂ emission allowance purchases.

8

9 The Company has determined that the least cost compliance strategy to
10 meet SO₂ emission allowance limits is a combination of burning low sulfur
11 coal, installation of emission control technologies as discussed by Mr. Skiles
12 Boyd, and utilizing SO₂ emission allowances. In effect, SO₂ emission
13 allowances are a component of the "as burned" booked cost of coal. The
14 Company's utilization of SO₂ emission allowances (versus burning low
15 sulfur coal) results in a direct savings to the Company's customers in terms
16 of lower delivered fuel costs. In other words, notwithstanding the emission
17 reductions obtained from the installation of emission control technologies,
18 the purchase of SO₂ emission allowances and higher sulfur coal results in
19 the lowest total compliance costs as compared to utilizing entirely low sulfur,
20 higher cost coals. Accordingly, it is appropriate to recover the prudently
21 incurred costs of the SO₂ emissions allowance expense through the PSCR
22 mechanism. The MPSC Staff has supported the inclusion of SO₂ emission
23 allowance costs as a cost of power in the Company's 2006 PSCR Plan
24 Case No. U-14702. (MPSC Staff Initial Brief p. 4)

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1

2 The utilization of purchased power also has an impact on the quantity of
3 allowances required each year. All other factors being equal, additional
4 purchased power will reduce the number of required SO₂ emission
5 allowances since the Company will generate less power to serve its load
6 requirement.

7

8 Similarly, third party wholesale power sales affect the amount of required
9 allowances. The Company can reduce its bilateral third party wholesale
10 power sales and/or increase bilateral power purchases and thereby reduce
11 its internal generation and hence its need for SO₂ emission allowances.
12 However, the real time power purchases and third party wholesale power
13 sales are a result of the economic dispatching of the Company's generating
14 resources by MISO and not by the Company. Clearly, tight integration and
15 optimization among fuel types, purchased power, interconnection sales, and
16 SO₂ emission allowances is required. Furthermore, SO₂ emission
17 allowance expense will shift based on system conditions, fuel prices and
18 purchased power costs. For these reasons the Company believes the
19 PSCR process is an appropriate regulatory mechanism to collectively
20 review these costs and provide for their recovery. Just like NO_x emission
21 allowances, SO₂ emission allowances are used up or "burned" in the
22 process of burning fuel for electric generation. NO_x emission expenses are
23 included in the PSCR costs and SO₂ emission allowance expense should
24 also.

25

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1 **Q. Is Detroit Edison's fossil fuel supply plan based on the Company's**
2 **purchase and consumption of SO₂ emission allowances?**

3 A. Yes. In order to burn the fuels identified in the Company's fossil fuel supply
4 plan, the Company must acquire and consume SO₂ emission allowances to
5 comply with EPA environmental requirements.

6

7 **Q. Could Detroit Edison purchase increased quantities of lower sulfur**
8 **coals and decreased quantities of higher sulfur coals as a means to**
9 **avoid purchasing the SO₂ emission allowances?**

10 A. As a practical matter, it could not. Wherever possible, the Company's
11 generation units economically blend low, mid, and high sulfur eastern coals
12 with low sulfur western coals. System load requirements, equipment
13 capabilities, environmental regulations, and economics are used to
14 determine the appropriate blend. Low sulfur western coal use is maximized
15 based upon the above-mentioned variables with higher sulfur eastern coal
16 used in the remaining portion of the coal blend. The higher sulfur coals are
17 needed to optimize precipitator performance. The higher heating values
18 that are generally characteristic of the higher sulfur coals purchased by the
19 Company are also needed to optimize boiler and boiler-related equipment
20 performance. Therefore, the replacement of higher sulfur eastern coals with
21 lower sulfur eastern coals can come at the expense of decreased low sulfur
22 western coal use and increase the overall system fuel expense based upon
23 the forecasted system load requirements, coal costs, and SO₂ emission
24 allowance costs.

25

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1 **Q. Could Detroit Edison install equipment such as scrubbers to reduce**
2 **its reliance on SO₂ emission allowances?**

3 A. Yes. As I previously mentioned and as is more fully described by Mr. Skiles
4 Boyd, the Company is pursuing an aggressive strategy to install equipment
5 to reduce its SO₂ emissions, through the installation of scrubbers on Monroe
6 unit 4 in the fall of 2008, Monroe unit 3 in the spring of 2009, Monroe unit 1 in
7 the spring of 2010, and on Monroe unit 2 in the fall of 2010.

8
9 To summarize, SO₂ emission allowance costs are a component cost of fuel
10 burned for electric generation which will vary in concert with native
11 generation and market prices. SO₂ emission allowances are an integral part
12 of prudent fuel procurement and utilization evaluations. Consequently, the
13 Company is requesting Commission approval for including the SO₂
14 emission allowance expense as an expense recoverable through the PSCR
15 clause. If the expense is not recovered as part of the PSCR, then it must be
16 included as part of the base rates.

17

18 **Q. What has been the market price of SO₂ allowances?**

19 A. The market price of SO₂ allowances has ranged from about \$40/ton to
20 \$1,600/ton. In the last two years the market price has ranged from about
21 \$200/ton to \$1,600/ton. As shown on Exhibit DE-16, Schedule F8-9, the
22 average cost of the SO₂ emission allowances that the Company purchased
23 for 2005 was \$75/ton.

24

25 **Q. Can you describe Exhibit DE-16, Schedule F8-10?**

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1 A. Yes. Exhibit DE-16, Schedule F8-10 is the Company's projection of the
2 mercury (Hg) emission allowance expense.

3

4 **Q. Why is the Hg emission expense shown as starting in 2010?**

5 A. On March 15, 2005, the Environmental Protection Agency issued the first-
6 ever federal rule to permanently cap and reduce mercury emissions from
7 coal-fired power plants. This rule makes the United States the first country
8 in the world to regulate mercury emissions from coal-fired power plants.

9

10 The Clean Air Mercury Rule establishes "standards of performance" limiting
11 mercury emissions from new and existing coal-fired power plants and
12 creates a market-based cap-and-trade program that will reduce nationwide
13 utility emissions of mercury in two distinct phases. The first phase cap is 38
14 tons. EPA has set the State of Michigan allocation budget for Phase I (2010
15 – 2017) at 1.303 tons. In the second phase, starting in 2018, coal-fired
16 power plants will be subject to a reduced cap, which will reduce emissions
17 to 15 tons upon full implementation. The Michigan budget for Phase 2 is
18 0.514 tons.

19

20 The Clean Air Mercury Rule includes a model cap-and-trade program that
21 states can adopt to achieve and maintain their mercury emissions budgets.
22 States may join the trading program by adopting the model trading rule in
23 state regulations, or they may adopt regulations that mirror the necessary
24 components of the model trading rule. The projection of Hg emission

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1 allowance expense is based on the trading model. The emission budgets
2 are permanent, regardless of growth in the electric sector.

3

4 **Q. What is the Company's Hg emission cap for Phase 1?**

5 A. The State has not completed its State-specific rule making which will define
6 the emission requirements. The Company has assumed an allocation of
7 1,236 pounds.

8

9 **Q. Are the projections of Detroit Edison's emission allowances (NO_x, SO₂,
10 and Hg) and associated expenses reasonable?**

11 A. Yes, the Company's emission reduction strategy (as discussed by Mr. Boyd)
12 and the projections of emission allowance expenses are reasonable and
13 prudent. As shown on Exhibit DE-16, Schedules F8-8, F8-9, and F8-10, to
14 supply the allowances consumed, the Company will utilize the allocated
15 allowances, allowances in inventory and allowances purchased from the
16 market. The Company will maintain a certain level of allowances in
17 inventory in case of contingencies such as increased generation, allowance
18 market illiquidity, or delay of emission reduction equipment. The Company
19 will purchase NO_x emission allowances to avoid losing 2 for 1 due to flow
20 control.

21

22 **Q. What is contained in Exhibit DE-16, Schedule F9?**

23 A. Exhibit DE-16, Schedule F9 shows annual capacity factors for the
24 Company's power plants, peakers and Ludington for the years 2005 through

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1 2011. I am supporting the capacity factors shown for all of the plants,
2 except Fermi 2. Mr. Wayne Colonnello will support the Fermi 2 capacity
3 factors.

4

5 **Q. How is capacity factor defined?**

6 A. Capacity factor is the ratio of the net electric generation in the period divided
7 by the product of the net demonstrated operating capability multiplied by the
8 hours in the period and expressed as a percent.

9

10 **Q. Can you explain Exhibit DE-16, Schedule F11?**

11 A. Yes. Exhibit DE-16, Schedule F11 shows a summary of all fuel and
12 purchased power costs by the various categories for the period 2005
13 through 2011.

14 The Net System Output - Electric expenses shown on Exhibit DE-16,
15 Schedule F11 exclude the Industrial Send Out Steam expense which was
16 developed by Mr. Gary Lapplander.

17

18 **Q. What is the network transmission expense?**

19 A. The network transmission expense is the projected network transmission
20 expenses to serve the full service customer requirements as charged by
21 MISO. Mr. Shields describes these expenses and supports the expense
22 projections shown on Exhibit DE-16, Schedule F7-4.

23

24 **Q. What is the Wolverine Adjustment?**

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1 A. The Company has made a long-term FERC jurisdictional wholesale for resale
2 power sale to the Wolverine Power Supply Cooperative which is part of the
3 Company's native load requirement. The costs incurred to make this sale are
4 excluded from the PSCR cost calculation, but the Company does not incur
5 network transmission costs due to this sale because Wolverine is responsible
6 for obtaining its own network transmission directly from MISO.

7

8 **Q. How was the R-10 adjustment shown on Schedule F11 determined?**

9 A. The R-10 adjustment was based on PROMOD runs with and without the R-10
10 load for determining the cost component. The R-10 adjustment includes fuel
11 expense, emission expense, purchased power expense and network
12 transmission expense.

13

14

15 **Q. Are the projections of Detroit Edison's generation, purchased power,**
16 **emission allowances (NO_x, SO₂, and Hg) and fuel additives and**
17 **associated expenses reasonable?**

18 A. Yes, the projections are reasonable and prudent. As has been previously
19 described, the projections of Detroit Edison's generation and purchased
20 power for the projection were developed using an economic dispatch
21 forecast model to reliably serve the energy and demand requirements of the
22 Company's full service customers based on fuel cost, market power costs,
23 and emission allowance cost. The forecast was evaluated based on
24 historical operation and expected changes due to maintenance schedules,

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1 fuel costs, market power prices and changes in NSO. The emissions
2 allowances were projected from the economic dispatch taking into account
3 the market price of emission allowances required for generation.

4

5 **Q. Does this complete your testimony?**

6 A. Yes, it does.