

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
VINCENT G. DOW

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF VINCENT G. DOW

Line
No.

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

2 A. My name is Vincent G. Dow. My business address is The Detroit Edison
3 Company, 2000 Second Avenue, Detroit, Michigan 48226.

4

5 **Q. Would you please state your educational background?**

6 A. I graduated from Lawrence Technological University with a Bachelor of
7 Science degree in Electrical Engineering. I earned my Masters of Business
8 Administration from Wayne State University. I am currently licensed as a
9 Professional Engineer by the State of Michigan.

10

11 **Q. Would you please describe your work experience?**

12 A. I have been employed by The Detroit Edison Company ("Detroit Edison" or
13 "Company") since 1979. I was first assigned to the Underground Systems
14 Department responsible for cable and streetlight installation and
15 maintenance. I worked in the Engineering area of the Company from 1980
16 until 1991. During this period, I held many positions with growing
17 responsibilities. The first of these positions was engineer, where I was
18 responsible for developing the maintenance program for the underground
19 distribution system and the streetlight system. I was also responsible for
20 developing overhead and underground lines standards. During this period, I
21 also designed line construction work for customers. My next role was as
22 engineer in the Research area. In this role, I was responsible for the
23 research testing of polymer cables to determine the end of life and cause of

1 failure. I then worked as an engineering work leader responsible for
2 direction of engineers and technicians in the development of overhead and
3 underground line specifications. I worked as the Supervisor of Tools and
4 Equipment responsible for the supervision of engineers, technicians and
5 repairmen in the specification, testing and development of work standards
6 for tools and equipment used by distribution and customer service
7 personnel. In 1988, I became the Supervising Engineer of the
8 Environmental and Operating Practices area. I was responsible for the
9 supervision of Engineers and Technicians in the development of operating
10 practices for the distribution system, development and auditing of the
11 environmental practices used in the distribution and transmission area and
12 the emergency preparedness planning for customer outages. During this
13 assignment, my department implemented the use of weather systems for
14 predicting outages and the first automated outage management system
15 used at Detroit Edison.

16
17 In 1991, I moved to the role of Assistant Director of Operations in the thumb
18 service area. In this role, I was responsible for the operation of five service
19 centers performing maintenance, operations and construction of the
20 distribution and transmission system. Upon reorganization, I moved to
21 Director of Marysville Service Center. In this role, I was responsible for the
22 electrical system design, construction, maintenance, and operation in St.
23 Clair County.

1 In 1992, I was asked to work on the Company's new Work Management
2 System. Over the next two years, I was responsible for the development
3 and implementation of a work management system for the Distribution
4 Operation area that integrated customer and internally generated work with
5 design, financial reporting, material ordering, timekeeping, and construction
6 scheduling.

7
8 Starting in 1995, I worked in the Customer Service area for six years. The
9 first position was Director of Field Service. In this position, I was
10 responsible for meter installation, maintenance and testing for Detroit
11 Edison. In 1997, I was promoted to Assistant Manager of Customer
12 Service. I was responsible for the implementation of changes in the
13 Customer Service organization. In 1998, I took a one-year assignment as
14 the Manager of Culture Change for Energy Distribution and in 1999 I
15 returned to Customer Service as the Assistant Manager of Customer
16 Service with direct responsibility for managing the call center. In this role,
17 we initiated an action plan to return the call center to best-in-class
18 performance. In 1999, I was the Manager of Customer Service responsible
19 for the entire Customer Service Operation of Detroit Edison including phone
20 center, field service, meter engineering, credit and collection, billing, and
21 process improvement.

22
23 **Q. Please describe more recent positions and duties.**

1 A. My last two positions were Director of Power Delivery Operations and
2 General Director of Billing and Customer Service Processes. In 2001, I
3 moved to the position of Director of Power Delivery Operations responsible
4 for the operation of the Detroit Edison transmission and distribution systems.
5 My responsibilities included managing the control center, emergency
6 planning and restoration, public safety, protective tagging, operations
7 engineering and power quality areas for the safe and efficient delivery of
8 electricity to 2.1 million customers. In 2003 I became the General Director of
9 Billing and Customer Service Processes. I was responsible for the utilization
10 of meter reading data, bill calculation, and the bill mailing process. In the role
11 of Customer Service Process Owner, I was responsible for the integration of
12 the processes used to provide customers access to our service, render a bill
13 and collect payments.

14

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

16 A. I am presently Vice President of Distribution Operations. I am responsible for
17 overall field operations of Detroit Edison's electrical distribution system,
18 including distribution and substation operations, outage restoration, new
19 customer connections, and all distribution system construction.

20

21 **Q. Are you a member of any professional organizations?**

22 A. Yes, I am a member of the Engineering Society of Detroit. I am also on the
23 board of directors and executive committee of the Better Business Bureau
24 of Southeastern Michigan and the Gleaners Community Food Bank.

1

2 **Q. Have you previously testified in a rate case?**

3 A. Yes, I testified on behalf of Detroit Edison in MPSC Case No. U-13808. I
4 presented testimony supporting the operation and costs of the Energy
5 Distribution and Customer Service areas.

6

THE DETROIT EDISON COMPANY
DIRECT TESTIMONY OF VINCENT G. DOW

Line
No.

1 **Q. Please describe the purpose of your testimony.**

2 A. The purpose of my testimony is to support, as reasonable and necessary,
3 the expected capital expenditures and O&M expenses related to Distribution
4 Operations and Electric Choice for the test year of 2007. In addition, I will
5 support, as reasonable and necessary, the actual 2005 expenditures and
6 expenses, the expected 2006 and estimated 2008 through 2011
7 expenditures and expenses. I will describe the major segments and driving
8 forces behind this spending and discuss the organizations that incur these
9 costs and discuss the effect of the Performance Excellence Process (PEP)
10 on these organizations. I will also discuss innovative engineering solutions
11 involving distributed generation and automatic meter reading (AMR)
12 technology and productivity improvements that help offset cost increases
13 despite the pressures of electrical system expansion and inflation.
14 Furthermore, I will describe the current issues facing the Company with
15 regard to customer satisfaction.

16

17 **Q. Please explain the types of things that fall into the Capital and O&M**
18 **categories?**

19 A. In broad terms, Distribution Operations capital expenditures are made to
20 provide direct connections of new customers to the electric system, delivery
21 to increased loads of existing customers, electric service reliability and the
22 Company's storm response capabilities. O&M expenses are incurred to
23 cover the operating and maintenance costs for Distribution Operations for

1 areas such as line clearance and storm related costs and the operation of
2 the Company's electric choice program.

3

4 **Q. What exhibits are you sponsoring?**

5 A. I am sponsoring Exhibit DE-16, Schedule F3-5, "Energy Delivery and
6 Customer Service - Capital Expenditures 2005 - 2011" and Exhibit DE-16,
7 Schedule F5-3, "Energy Delivery - O&M Expense 2005 - 2011."

8

9 **Q. Were the above-mentioned exhibits prepared by you or under your**
10 **direction?**

11 A. Yes, they were.

12

13 **Q. What Detroit Edison organizations will you cover in your testimony?**

14 A. My testimony will cover Distribution Operations and the Electric Choice
15 organization.

16

17 **Q. Can you please describe Distribution Operations?**

18 A. Distribution Operations is responsible for engineering, operation,
19 construction and maintenance of the Company's distribution, and
20 subtransmission systems and substations. As part of the Company's PEP
21 initiative, Distribution Operations has been reorganized into five
22 organizations.

23

24

1 **Q. Can you please describe the five organizations?**

2 A. Yes, Asset Optimization is responsible for setting high-level budget priorities
3 for Distribution Operations, optimizing capital/O&M spend, day-to-day and
4 emergency operation of the electrical system and development of the
5 electrical system reliability, restoration, storm, line clearance and
6 maintenance plans. The group also plays a strategic role in network
7 reliability, resource forecasting and technical support and serves as a liaison
8 to Supply Chain. Additionally, Asset Optimization performs benchmarking
9 activities and participates in industry organizations.

10

11 Planning and Design identifies specific projects, new business requirements
12 and maintenance needed to improve customer satisfaction and reduce
13 costs. The organization moves system projects from conceptual design to
14 fully executable work packages and is responsible for developing and
15 maintaining design and construction standards. This organization includes
16 four regional groups located to best address system and community needs,
17 power quality concerns and customer connections for small and large
18 customers.

19

20 Resource Management is responsible for effectively matching resources to
21 the required work and to ensure that all work is accomplished on time, to
22 scope and on budget. This includes construction projects, connecting new
23 customers, line clearance, system maintenance and other improvement
24 efforts. The group also oversees and manages dispatch, capacity planning,

project management and contractor management to prioritize and assign planned and unplanned work.

Service Operations is focused on day-to-day operations. This group is responsible for the construction, operation and maintenance of the overhead, underground and metering systems.

System Engineering and Equipment is a group of engineering and equipment specialists that support the entire system. This group also includes substation field staff that is managed centrally but located regionally. The group's responsibilities include material specifications for system equipment, engineering and technical support for field jobs and the operation and maintenance of the Company's substations.

An AMR team is also being formed to develop the Company's AMR strategies, specify systems and create rollout and maintenance plans.

Q. Would you please describe the role of the Electric Choice organization at Detroit Edison?

A. The Electric Choice organization is responsible for developing and managing the processes for customers migrating between bundled electric services and energy supply from an Alternative Electric Supplier with continuing delivery service from Detroit Edison. The post-implementation organization is comprised of three main areas: Supplier Transactions,

1 Customer Transactions and Program Management. Supplier Transactions
2 is responsible for managing the relationship between Detroit Edison and
3 suppliers participating in the Electric Choice program. This operation
4 includes education of suppliers on the requirements for program
5 participation and assisting the suppliers with registration, enrollment and
6 billing functions.

7
8 Customer Transactions is responsible for assisting customers with issues
9 related to their interest or involvement in the Electric Choice program,
10 particularly regarding the areas of customer notification, documentation,
11 enrollment and billing.

12
13 Program Management is responsible for overall coordination of the Electric
14 Choice program at Detroit Edison. This effort includes the development of
15 technology to support the program, communication needs for the program,
16 process management and the supply, coordination, back office support and
17 installation of interval meters and metering equipment currently required for
18 the program.

19
20 **Q. What are the major customer satisfaction issues facing Distribution**
21 **Operations?**

22 A. The two major customer satisfaction issues facing Distribution Operations is
23 the frequency and duration of outages. In August 2005, the Michigan Public
24 Service Commission issued an Order in Case No. U-14603 expressing its

1 concern regarding reliability. The commission's order noted that this was
2 not necessarily a cause for concern given the significantly higher summer
3 temperatures, but identified 19 zip codes in Detroit Edison's service territory
4 to be investigated by the Company. Detroit Edison's October 2005
5 response agreed with the commission that the increase in complaints was
6 driven by the summer of 2005 being atypically hot. However, the Company
7 has initiated a reliability improvement program which includes increased line
8 clearance and additional capital projects to increase service reliability. In
9 2006, an additional 150 capital projects have been undertaken, and 51 line
10 clearance jobs have been accelerated or added. This work is scheduled to
11 be performed in 2006 on 140 distribution circuits. The Company plans to
12 maintain this level of reliability improvement in future years.

13
14 Detroit Edison has focused on day-to-day restoration improvement in 2004
15 and 2005 and has made significant progress. In 2003, Detroit Edison's day-
16 to-day restoration time, as measured by the customer average interruption
17 duration index (CAIDI) as defined in IEEE 1366-2003, section 4.2.3, was
18 256 minutes. This implies that a customer who experiences an outage
19 could expect to be without power for 256 minutes. This statistic improved
20 by 23 minutes in 2004 and an additional 40 minutes in 2005. Detroit
21 Edison's 2005 CAIDI is 193 minutes, a 25% improvement compared to
22 2003. The Company is also improving customer satisfaction with
23 restoration estimates by ever-increasing the frequency of their availability
24 and continuing to advance their accuracy. Additional restoration

enhancements have been identified through the PEP and are expect to continue to support progress.

Q. Describe in more detail the above mentioned reliability improvement efforts?

A. Recently, system average interruption frequency index (SAIFI) has increased to the second quartile, and Detroit Edison intends to return SAIFI performance to first quartile. Additionally, while still within the reliability standards established by MPSC Case U-12270, the number of pockets of customers with frequent outages has increased recently. This is another trend the Company has targeted for improvement. To accomplish this, the Company will primarily expand well understood reliability plan strategies. The Company's reliability plan has three major strategies: prevent outages, reduce the number of customers affected by an outage, and speed restoration. Execution of this plan since 1991 has led to a 27 percent reduction in the frequency of interruption. One of the most effective ways of reducing and maintaining frequency is line clearance. In 2006, the Company increased its line clearance program and plans to maintain this level of investment and couple it with productivity and other improvements to increase the number of miles trimmed each year.

Additionally, improvements to the secondary system and proactive replacement of distribution transformers will address potential low voltage problems on circuits predicted to become heavily loaded due to increased

1 demand of existing customers.

2
3 The Company will also focus on subtransmission and distribution circuit
4 improvements and maintenance such as installing spacer cable and
5 rerouting circuits in areas where normal line clearance has not proven to be
6 effective due to tall overhanging trees. Spacer cable has proven to be a
7 very effective method of reducing outages in targeted areas with up to an
8 80% reduction in outages after installation. These projects will be coupled
9 with periodic circuit upgrades, such as replacing aging equipment, restoring
10 broken cross arms and braces and upgrading or replacing poles. New
11 circuits will also likely be added to reduce loading per circuit.

12
13 **Q. Can you explain the reducing the number of customers affected and**
14 **speeding restoration strategies?**

15 A. All outages cannot be prevented and a key strategy of reliability planning is
16 to reduce the number of customers affected by an outage. This is
17 accomplished through the addition of substations and distribution circuits.
18 These substations and circuits are needed to offset the negative effects of
19 load growth. In the 1990s, an expanding economy accompanied by a
20 migration of load to outlying suburbs caused the reserve capacity in the
21 substations to be used quickly. A measure of this is a substation system
22 reserve factor, which is calculated by dividing the total amount of load that is
23 capable of being served from all of the installed substations by the peak
24 demand on the system. In other words, this calculation is a reflection of

substation reserve capacity to meet load. In the early 1990s, this reserve factor averaged 1.23, indicating a reasonably safe aggregate reserve margin of 23% to meet peak load. From 2001 to 2005, the reserve factor averaged 1.14 and is lower in some regions.

Circuits are also becoming heavily loaded. The peak demand on the 13.2 kV system has grown 64 percent from 1991 through 2005. In order to offset the negative effect of growth on reliability performance, it is imperative to add new circuits. The 13.2 kV frequency of interruption increases by 0.045 for every 1 MVA increase in load per circuit. In order to maintain the 13.2 kV average circuit loading to between 6.5 and 7.0 MVA per circuit, it is necessary to add approximately between 20 and 30 new 13.2 kV circuits per year. In addition to new circuits, existing circuits are also broken up into smaller blocks with additional sectionalizing and branch fusing to minimize the customers affected by an outage. Manual three-phase switches are also being installed to break the circuit up into smaller blocks. Sometimes large commercial and industrial loads trigger the need for a new substation.

Where an outage cannot be prevented and the numbers of customers affected has been minimized, the reliability planning strategy is to design the system to speed restoration. Where possible, the new circuits are configured in a primary auto-loop design. This design allows for large portions of customers on an outage-affected circuit to be automatically transferred over to an adjacent energized circuit. In addition, new

1 substations and circuits are added with distribution automation equipment to
2 allow remote operation and monitoring of the distribution system. This will
3 allow the restoration of customers who can be separated from the point of
4 trouble within minutes, rather than hours, following a restore before repair
5 restoration policy. Remote monitoring will also detect overloaded or
6 unbalanced conditions before emergencies occur. Further detail on these
7 programs will be provided in the capital and O&M sections of this testimony.

8
9 **Q. Other than the uncommon temperatures that you mentioned, were**
10 **there other things atypical about 2005?**

11 A. Yes, in 2005 the restoration efforts due to hurricanes in the southern states
12 created a significant demand on the national pool of overhead linemen and
13 line clearance resources. This created a considerable gap for several
14 months for Detroit Edison between labor resources and system construction
15 and maintenance requirements. This resulted in some planned work not
16 being completed in 2005. The work not completed and associated
17 spending was small, less than 3% (~\$10 MM) of the 2005 capital budget
18 and 8% (~\$2.7 MM) of the 2005 line clearance budget. If this work is not
19 completed on an ongoing basis, the impact could lead to degradation in
20 service levels and reductions in customer satisfaction.

21
22 The storm O&M expenses were slightly higher than the average storm year.
23 Detroit Edison has averaged storm expenses of \$57 MM over the last five
24 years. This includes the 2005 expenses of \$60 MM. The temperatures in

2005 were significantly higher than previous years which resulted in the increased expenses. Although these expenses were above the average, they were not the highest storm expenses seen on the system. Other non-storm restoration expenses in 2005 were \$58 MM compared to the five year average of \$64 MM. The ability to forecast weather conditions on a long term basis makes the estimate for storms and other restoration efforts best done on a historical basis. Therefore, the total 2005 restoration expenses are not out of line with the average.

Q. Please describe what changes Performance Excellence Process (PEP) will have on your Distribution Operations?

A. Several PEP improvements are anticipated from consolidation of functions, standardization of equipment and various activities, and creating productivity improvements and process enhancements. I anticipate that the associated personnel reductions will primarily occur in office staff functions. For example, the consolidation of planning activities will allow for increased span of management control and better utilization of back office support staff. However, the Company is increasing field resources as part of PEP efforts.

The Company has analyzed best sourcing practices and engineering specifications to standardize equipment and construction standards. One innovate example is what has been named the "Pad Mount Substation." A Pad Mount Substation includes a transformer, regulators and a recloser in

an arrangement that can more easily and less expensively be sited than a traditional substation. They are capable of serving loads less than 7.5 MVA. These Pad Mounted substations are more compact and esthetically pleasing than the traditional substation design and can be placed in locations where traditional substations cannot. For these reasons, we expect a more receptive community approval process.

Regarding productivity improvements and process enhancements, the Company has initiated three projects focused on overhead construction crews, planners and substation operation and maintenance resources. These projects seek improved performance through identification and delivery of training, enhanced tools and processes and better productivity measures. Another idea in the area of process enhancements is the elimination of duplicate service inspections. Currently inspections for new services are completed numerous times by different parties. A PEP idea is being advanced that would eliminate some of these redundant inspections. This concept if fully realized will make a significant contribution to PEP savings and is included in the PEP savings calculations.

The Company has also initiated the above mentioned reliability improvement program. Line clearance and capital projects will all be increased as part of this effort, and this increased effort is expected to reduce reactive maintenance activities, primarily associated with storm restoration. Customers will benefit from reduced outages, quicker

restoration and related cost reductions, which have been included in the PEP savings.

Q. Please describe how the Performance Excellence Process will impact your customer satisfaction?

A. PEP will support reliability improvements. Detroit Edison's goal with respect to frequency of outage, as measured by IEEE 1366-2003, section 4.2.1 system average interruption frequency index (SAIFI), has been to maintain first quartile status. In 2005, Detroit Edison's SAIFI increased from 0.95 to 1.03. This coupled with the issues in the summer of 2005 has led the Company to increase the reliability improvement program including a major effort to reduce pockets of customers experiencing frequent outages. This program will improve SAIFI and avoid the pockets of customer complaints that arose in the summer of 2005. Without this program, there is potential for an increase in SAIFI, power quality problems and pockets of customers experiencing frequent outages and an associated decline in customer satisfaction.

The PEP improvement ideas will also improve customer satisfaction related to outage restoration. One of the primary tactics for this area of improvement is the consolidation of dispatching functions. The capacity planning and dispatching of resources for restoration, construction and customer connection work will occur from the same organization to improve the balancing of resources to ensure that critical work is completed on time.

1 Additionally, day-to-day restoration will benefit from proposed new shift
2 coverage.

3
4 One of the major themes of the PEP has been to increase accountability
5 and reduce handoffs. One example of this is the new Planning and Design
6 organization. This group is combining the previously separated functions of
7 distribution planning and power quality and will organize into four regions.
8 Each of these groups will act as regional asset managers for the associated
9 distribution system and maintain responsibility for system design and
10 performance, regional capital and O&M costs and local customer
11 satisfaction. Each region will be further divided into two sub-regions with a
12 principal engineer – ombudsman responsible for that area. These highly
13 qualified engineers will be liaisons for customers with service problems and
14 have the authority and responsibility for addressing these issues quickly and
15 permanently through maintenance and construction activities. They will be
16 the work leaders of teams of engineers and technicians to support this
17 critical responsibility. Because the Company is doubling the number of
18 ombudsman positions from four to eight, customers with service problems
19 will receive increased attention, and by adding system design authority and
20 responsibility to these positions, better and timelier solutions will result.

21
22 In addition, all organizations within Distribution Operations will interface with
23 Asset Optimization to optimize overall capital and O&M spending and
24 Resource Management to allocate the necessary manpower. Another

improvement is the integration of engineering functions to fully leverage the available knowledge base to best identify the optimal material specifications and address equipment issues.

Q. Will the Company's PEP efforts affect the capital expenditures and O&M expenses for Distribution Operations?

A. Yes, the Company's PEP efforts and associated savings are expected to mitigate a portion of the impact on rates of equipment and fuel cost increases, reliability improvements, and other budget demands. In the case of equipment cost increases, the primary materials for the Company's major equipment purchases are copper, aluminum and steel, which according to Bloomberg have increased at 35%, 15% and 24% CAGR respectively between January 2002 and March 2006. These cost increases well outpace normal inflation. A known and measurable adjustment has not been made for the expected increase in materials cost and represents a significant risk to maintaining the costs included in the exhibits that I am sponsoring. PEP savings are anticipated to offset some of these cost increases.

In addition, the Company initiated a Capital Utilization Improvement effort to support funding for reliability improvements. This team consisted of engineers from diverse disciplines, and their mission was to investigate methods of reducing the cost of the most typical and capital intensive projects. The savings were reinvested in reliability projects to improve customer satisfaction. The team identified numerous innovative engineering

1 solutions that amounted to an annual \$2 MM savings. These savings have
2 been incorporated into the 2005 budget and PEP savings.

3
4 The organizational changes previously discussed will result in reductions of
5 full-time equivalent (FTE) positions and cost savings. The projected 16%
6 FTE reduction in Distribution Operations includes open positions and
7 positions currently filled on contracts. The annual cost savings for
8 Distribution Operations is approximately \$21 MM in capital and \$34 MM in
9 O&M.

10
11 **Q. What other initiatives are in process or planned to increase the**
12 **efficiency of operations and improve customer service?**

13 A. The Company is planning a deployment of AMR technology in the electric
14 service territory to provide numerous customer benefits, including increased
15 accuracy and access to meters and improved quality and reliability of
16 energy delivery. In addition, several Customer Service related AMR
17 benefits will occur and are discussed in the testimony of Mr. Broome.

18
19 **Q. What has changed that makes AMR attractive now? Why hasn't this**
20 **been done before at Detroit Edison?**

21 A. AMR has become increasingly more cost effective over the last several
22 years. The increased market maturity over the last 10 years, combined with
23 the technological maturity has increased cost effectiveness making this
24 deployment a prudent endeavor. AMR has been widely deployed for over

a decade throughout the U.S. and in Europe and has now reached maturity. Although technology will always be moving forward, we are confident that today's technology will allow us to realize substantial benefit throughout the project's lifetime of about 20 years. Waiting for a new technology will just delay the Company's ability to provide these service and operational improvements.

Q. Elaborate on the expected benefits of AMR?

A. An AMR system will nearly eliminate manual meter reading and common issues related to the accuracy and accessibility of manual reads. Reads will average near 100%, far exceeding the MPSC standards. Reads will be obtained by technology and delivered to the Company's billing system automatically and not be subject to interpretation by the reader or potential transposition errors.

Gaining access to meters on customer properties has been an issue with traditional methods. AMR will reduce these issues dramatically and provide security for both customers and employees. There will be fewer cases of a customer mistakenly thinking his/her property is being invaded. Employees will face far fewer issues with dogs, fences and locked gates.

AMR will also provide improved quality and reliability of energy delivery by providing remote monitoring of the distribution network and enable the following:

- 1 o Faster and more reliable outage detection and restoration
- 2 ▪ The AMR network will feed the Company's outage systems
- 3 information on which meters or groups of meters are not
- 4 responding. This will support enhanced locating of damage.
- 5 ▪ Near the end of restoration efforts associated with a storm,
- 6 issues referred to as trouble-behind-trouble can be
- 7 problematic. These issues arise when damage is not
- 8 discovered until other restoration efforts are completed on
- 9 the same circuit. With AMR, these issues can be minimized.
- 10 Restoration crews can receive data on which meter are
- 11 responding before they leave a customer site or area.
- 12 Pinging the meter will become commonplace as the
- 13 technology is used to determine customer outages and
- 14 pinpoint timely correction.
- 15 o More efficient and informed planning of the distribution system
- 16 ▪ Planning engineers will draw on daily reads to propose more
- 17 effective load related capital projects.
- 18 ▪ More extensive and accurate outage information will allow
- 19 for better root cause analysis and improved reliability
- 20 projects
- 21 o Enhanced transformer load management
- 22 ▪ With the AMR network, engineers will be able to locate
- 23 specific transformers with load problems and have them
- 24 replaced before they are damaged.

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Utilization of AMR will result in more timely and accurate reads. This will improve our relationships with customers by reducing a common point of contention, estimated reads. Furthermore, the technology provides tampering detection to reduce theft and can provide remote disconnect / reconnect functionality that can drastically increase the efficiency of customer disconnection and timely restoration.

Q. Who is using this technology today?

A. The Company has conducted many site visits and or telephone interviews with various utilities across the nation. These utilities have initiated or have completed varying degrees of AMR installations and used different technologies and vendors. In the United States, there are at least 15 utilities with over 500,000 meters each that have or are in the process of installing AMR technology. PPL and PECO have installed over 1.3 million and 2.1 million AMR endpoints respectively. Here in Michigan, the co-operative electric companies including Cherryland, Cloverland and Great Lakes Energy cooperative are very actively utilizing AMR technology. SEMCO has also utilized mobile technology for many years.

Q. Which technology and vendor has been selected?

A. We have not chosen a specific vendor. However our initial analysis indicates that a primarily "Fixed AMR" solution offers the best combination of benefits and future functionality for the associated costs.

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Q. Please describe the implementation plan you will be following for AMR?

A. The Company has conducted numerous pilots and experiments utilizing Automated Metering and related technologies to prepare for efficient deployment and implementation. AMR deployment will occur using a phased in approach beginning with areas with the highest density of meters. The Company anticipates installing as many as 2200 electric meters per day and has scheduled full service territory implementation in approximately six years.

CAPITAL EXPENDITURES

Q. Please explain Exhibit DE-16, Schedule F3-5, “Energy Delivery and Customer Service Capital Expenditures 2005 - 2011.”

A. Exhibit DE-16, Schedule F3-5, identifies the 2005 actual capital expenditures broken out into various categories. Inflation is applied to the total 2005 expenditures and adjusted for PEP and known and measurable changes to forecast the 2006 through 2011 expenditures.

Q. Describe the capital expenditures for the connection of new business customers to the electrical system.

A. Line 6, Exhibit DE-16, Schedule F3-5, titled “Total New Business” provides capital expenditures for projects under \$100 thousand direct for electrical service to new customers and street lighting. This includes the costs of

1 extending existing lines by installing additional overhead or underground
2 lines and secondary services for new customers. It also includes the
3 installation of necessary overhead or underground lines, poles and lighting
4 fixtures for street lighting. The 2005 actual figures for meters and
5 distribution transformers (pole-top, pad-mount, etc.) are included on Lines 3
6 and 5, respectively. Any new electrical service greater than 250 kVA is
7 reviewed by Planning and Design to determine the impact on the distribution
8 system. If changes are required to the distribution system, and the cost of
9 those changes is greater than approximately \$100 thousand direct, Line 11
10 New Business Specific Projects is used.

11
12 **Q. Explain the Customer Advances for Construction.**

13 A. Line 7 of Exhibit DE-16, Schedule F3-5 titled "Customer Advances for
14 Construction" includes the recovery of capital investment that is over and
15 above normal service requirements, such as the difference between the
16 cost of installing underground and overhead services. It also includes
17 recovery for work performed at the request of others. The advances for
18 both small and large projects are included in this Line item. The main
19 influences on this category are changes in non-residential accounts and
20 construction of line extensions.

21
22 **Q. Explain the System Strengthening and Reliability Category on**
23 **Schedule F3-5?**

1 A. This category includes various categories of expenditures related to the
2 Company's efforts to increase reliability and strengthening the electric
3 system. Although the expenditures are made throughout the service
4 territory, the expenditures are driven by increasing load demands on certain
5 circuits and the overall effort to reduce poor performing electrical circuits
6 and pockets of customers experiencing frequent outages.

7

8 **Q. Do the capital expenditures address the customer's continued**
9 **expectations regarding electrical system reliability?**

10 A. Yes. Detroit Edison deploys capital that is in large part aimed at reliability
11 and system strengthening to implement the comprehensive reliability plan.
12 Lines 9 through 23 of Exhibit DE-16, Schedule F3-5 identify the capital
13 expenditures that address reliability and system strengthening. Additional
14 expenditures to support reliability improvement are included in Line 43.

15

16 **Q. Explain Line 9, Capital Line Clearance.**

17 A. Line 9 includes the capital expenditures for line clearance to allow the
18 upgrading and/or installation of overhead line facilities based on the specific
19 scheduled capital upgrades

20

21 **Q. Explain Line 10, Reliability/General Load Growth.**

22 A. The Reliability/General Load Growth Line item includes capital expenditures
23 regarding several reliability programs designed to prevent outages. The
24 programs include:

- 1 • The Pole-Top-Maintenance Program (PTM). PTM consists of
2 a visual patrol of the overhead lines in conjunction with an
3 infrared scan to identify problems. Replaced are such items
4 as poles, crossarms, insulators, lightning arrestors,
5 conductors, transformers, regulators and capacitors. The
6 overhead 4.8 kilovolts (“kV”) and 13.2 kV distribution circuits
7 and the subtransmission circuits are maintained on a 5-year
8 cycle. The program is not only effective from a reliability
9 standpoint, but the capital cost is offset by avoided costs to
10 repair and prevent outages.
11
- 12 • Another effective program is the Downed-Wire Reduction
13 Program (DWRP). Circuits with a high number of downed
14 wires are selected and scheduled for improvements including
15 conductor replacement.
16
- 17 • End-of-life Underground Residential Distribution cable
18 replacement and rejuvenation utilizing innovative techniques.
19
- 20 • The Transformer Load Management (TLM) program uses load
21 flow algorithms to identify overloaded distribution transformers
22 and proactively replace them before they fail causing outages
23 and oil spills.

24

- The secondary system improvement program targets areas that require improvement or replacement of copper wire on the secondary system.
- Other smaller programs include improved circuit lightning protection, reduction of pole ground resistance and the application of animal barriers in substations that have experiencing high levels of animal-caused outages.
- In order to address low voltage areas, there is a program each year to add capacitors to the system for voltage support or to rebuild or replace circuits that would exceed their emergency loading.

Also included in Line 10 are capital projects greater than \$100 thousand direct to address general system load growth and reliability needs driven by load increases.

Q. What is included in Lines 11 through 13 of that exhibit?

A. Line 11 includes projects greater than \$100 thousand direct that are designed to accommodate large new business load.

Line 12, Major Equipment, includes the large transformers and switchgear needed for the substation additions and expansion. With the projected

1 increase in system loads, additional substation transformers and switchgear
2 are required to meet the new load. As described previously, increases in
3 the costs associated with this equipment due to base material costs have a
4 major impact on the capital budget.

5
6 Line 13, Substation/Station Improvements, includes the cost to upgrade
7 existing substations based on the number of substations requiring
8 replacement of obsolete equipment and components that reached “end of
9 life.” Additionally, the Company has started replacing several types of
10 breakers that are well past their end of life. These breakers presented
11 significant maintenance and reliability concerns.

12
13 **Q. Describe the capital expenditures for Distributed Generation on Line**
14 **14.**

15 A. Distributed generation expenditures go to innovative applications of small
16 generation (up to 2 MW) on the distribution system. To date, the small
17 generators have been used to successfully provide current and voltage
18 support to areas of rapidly growing load where delays in obtaining local
19 community approval for a new substation created a risk of rolling blackouts.
20 Applications have also been used in situations that allow for the deferral of
21 substation transformer replacement in areas of low load growth where a
22 large increase in transformer capacity could not be fully utilized for several
23 years. Additional applications include shutdown of critical system elements

for maintenance without an interruption to customers while the maintenance is performed.

Q. Describe the System Strengthening Blanket expenditures.

A. System Strengthening projects with costs under \$100 thousand direct are listed in a System Strengthening blanket category. The System Strengthening Blanket category includes:

(1) Line 17: Projects to provide for increasing loads, including those to install, replace or remove transformers, regulators, pole-top switches, sectionalizing equipment, poles and overhead and underground conductors;

(2) Line 18: Projects to provide for miscellaneous system improvement, resulting in improved operating conditions such as to install, replace or remove fuses and automatic sectionalizing equipment, to install disconnect switches or to remove other electrical facilities no longer in use;

(3) Line 19: Projects to provide for relocation of facilities due to construction or modification of highways, water mains, public sanitation or at the request of municipalities or customers; also expenditures for work needed to make the poles ready for attachment by requesting joint users such as telephone and cable TV;

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- (4) Line 20: Projects to perform scheduled work for normal retirement unit change out (NRUC) items on the subtransmission, distribution, communication and street lighting systems;
- (5) Line 21: Projects to perform emergency replacement work for retirement unit change out (ERUC) items on the overhead and underground subtransmission, distribution, communication and street lighting systems. Capital expenditures for storms are also included in Line 21 (ERUC and Storm).

Each of the blanket categories is driven by increased loads and necessary system improvements to maintain the operation of the Company's electrical systems. Line 22 represents the sum of Lines 17 through 21.

- Q. Describe the expenditures included in General Plant.**
- A. General Plant, Line 25, includes tools and test equipment for field forces and for repair and fabrication shops. Included are purchases of large capital items such as vehicle for restoration and construction crews.
- Q. Explain Line 26, Substation Security.**
- A. Given concerns about vandalism and other nefarious activities, the Company has and will continue to make investments in substation

monitoring and protection. Additionally, spare equipment is being purchased and strategically placed around the service territory to allow for quick recovery from damage that could result from the concerning activities. The costs to complete these projects are included in 2005 and are expected to be an ongoing effort between 2006 and 2011.

Q. Explain Line items 27 and 28.

A. Non-Productive Labor Directs, Line 27, are the allocation of vacation, sick and holiday pay to direct capital labor. Removal Directs, Line 28, are the direct costs associated with the retirement of capital assets.

Q. What do Total ED Indirect Capital costs, Line items 30 to 34, reflect?

A. These costs include expenditures incurred as described on Lines 30 – 33. These costs are necessary to design the projects and provide the equipment, scheduling and coordination of capital work. The accounting adjustments reflect the outcome of a process performed at the end of each project to properly assign capital expenditures.

Q. Can you please describe Line 38, Inflation Adjustment?

A. This Line applies the inflation described in Exhibit DE-16, Schedule F1-1 starting with Line 37, Total ED Capital in 2005 to project needed capital from 2006 to 2011 without known and measurable adjustments.

Q. Can you please describe Line 40, PEP savings?

1 A. As discussed earlier in my testimony the PEP process resulted in the
2 identification of several process improvements, procedures, programs and
3 reorganization of functions resulting in system reliability and customer
4 service satisfaction increases while providing cost savings. Line 40 shows
5 the anticipated capital expenditure savings for years 2006 through 2011.

6

7 **Q. What impact will the Company's AMR system have on the capital**
8 **budget, Line 42?**

9 A. The project implementation plan has been structured to minimize any
10 single-year investment by spreading the capital expenditure over six years.
11 Given the very low risk nature of this project, we believe it is a very
12 attractive investment for which to secure debt and/or equity as needed.

13

14 **Q. What is the Reliability Improvement adjustment, Line 43?**

15 A. This is the adjustment to fund Detroit Edison's plan to return to first quartile
16 in SAIFI and reduce pockets of customers with frequent outages. Items
17 included are capital construction and line clearance. Also included in this
18 Line is an adjustment to account for increased substation transformer
19 purchases in 2006 to 2011 as compared to 2005. These transformers are
20 replaced annually due to internal winding, diagnostic test and ancillary
21 equipment failures. The overall replacement rate has been relatively
22 constant and does not show any significant trend. However, in previous
23 years the inventory of a number of specific types of transformers grew
24 beyond what was needed, and in 2005 this excess inventory was managed

1 to the proper level. Fewer transformers were purchased in 2005 than is
2 typical, and compared to 2005, additional transformers must be purchased
3 to maintain an appropriate inventory of specific types of transformers.
4 Without this inventory, large numbers of customers could experience long
5 outages when critical transformers fail and must be ordered with a long lead
6 time.

7
8 **Q. Describe any productivity efforts that have helped to control annual**
9 **increases in capital.**

10 A. The Company has continued its project-by-project review of requests for
11 new capital funding. The process includes a Project Value Analysis in
12 which teams of engineers, designers and construction employees are
13 brought together to work on ideas to lower overall project costs. The
14 resulting designs are reviewed by engineering experts from around the
15 Company to further reduce cost. This tiered design review process saves
16 the Company approximately \$8 MM to \$12 MM annually and has become
17 part of normal business operations over approximately the last five years.

18
19 Further the Capital Budget Utilization and PEP efforts that I described
20 earlier in my testimony help control capital spending. The Capital Budget
21 Utilization team developed methods that allowed the Company to increase
22 spending on reliability efforts without increases in the budget by using
23 different industry standards and equipment. This effort was extended in the

PEP initiative by improving processes that impact capital spending, such as design and construction.

Q. Are there any major risks to the cost estimates made in your testimony and exhibits?

A. Some of the primary materials used in electrical equipment are copper, aluminum and steel. Driven by increased global demand, the costs of these materials have increased far above inflation in the last few years. Between January 2002 and March 2006, the costs of copper, aluminum and steel have increased at 35%, 15% and 24% CAGR respectively. Given this history and global demand, material costs are expected to increase above inflation. Multi-variable regression models were used to forecast this cost pressure and resulted in a forecast of approximately 5.6% annual increase after 2006. Fuel costs have increased above inflation in recent years as well. According to Bloomberg, WTI has increased at 34% CAGR between January 2002 and March 2006. Based on a multiple regression forecast, fuel costs are expected to continue to increase by approximately 10.5% annually after 2006. These costs increased could lead to an increase over the inflation numbers used in the forecast.

Another risk follows from the fact that many communities have "Downtown Development Authorities" that seek to increase business traffic by, among other things, improving the aesthetics of their business district. The City of Taylor has designated a five-mile stretch of Telegraph Road as a Downtown

District, and has passed an ordinance requiring Detroit Edison to bury its entire distribution system in the Downtown District at the Company's cost. The Company feels that the MPSC has jurisdiction and the technical expertise necessary to rule whether the cost of relocation of overhead facilities should be at the cost of the utility customers outside of the City of Taylor or be borne by residents of the particular community. In June of 2003, the Wayne County Circuit Court decided that local city ordinance preempts MPSC regulations, and ordered the Company to pay the entire cost to repair contractor-installed conduit and to bury the existing overhead distribution system on a five-mile stretch of Telegraph Road. Upon appeal by the Company, this judgment was upheld in September 2004 by the Michigan Court of Appeals. In December 2004, the Company filed an Application for Leave to Appeal with the Michigan Supreme Court. Other companies, co-ops and municipal power authorities, and statewide organizations such as Consumers Energy, Michigan Municipal Electric Association, and the Michigan Electric Cooperative Association have all joined to file an amicus brief in support of Detroit Edison's position. If The City of Taylor's position is upheld and other communities take the same position, Detroit Edison's project costs could be substantially increased. Known and measurable adjustments have not been made for these and other risk items.

1 **Q. In your opinion, are the actual and projected capital expenditures for**
2 **Distribution Operations shown in Exhibit DE-16, Schedule F3-5 for the**
3 **years 2005 through 2011 reasonable and necessary?**

4 A. Yes, they are. I base my opinion on an analysis of historical expenditures,
5 my knowledge of the distribution system, strategic planning and reliability
6 plans.

7

8 **Q. Does that conclude your capital expenditure testimony?**

9 A. Yes. I would now like to address operation and maintenance expense
10 related to developing and maintaining the distribution system.

11

12 **O & M EXPENSES**

13 **Q. Please describe your general operation and maintenance expense**
14 **assumptions for the years 2006 through 2011.**

15 A. The assumptions used for the forecasts for 2006 through 2011 are based on
16 taking the 2005 actual figures and including the effect of inflation,
17 performance improvements and known and measurable changes.
18 Distribution Operations O&M expenses are primarily driven by weather and
19 maintenance requirements.

20

21 **Q. Please explain Exhibit DE-16, Schedule F5-3, "Energy Delivery O&M**
22 **Expense 2005 – 2011."**

23 A. Exhibit DE-16, Schedule F5-3 primarily reflects the operating and
24 maintenance costs for Distribution Operations. The expenses are shown for

Distribution Operation and Electric Choice. The operations and maintenance costs are for line clearance, storm and other associated costs. They include distribution and subtransmission costs. These costs are allocated to either operations or maintenance based on the application of FERC Accounting principles.

Q. Explain the Line Clearance costs.

A. Line clearance expenses as shown on Lines 2 and 7 are to meet the needs of the distribution and subtransmission system. Tree growth is trimmed away from the lines for both safety and reliability reasons. Line clearance is one of the most effective methods to improve reliability and reduce down wires, and it is critical to maintain customer satisfaction. The present line clearance cycle varies from three to six years based on voltage, tree density, reliability status and downed wire history for particular circuits. The line clearance costs for operations include the expenses to coordinate the line clearance maintenance work and contracts. In 2005, hurricane restoration efforts impacted the available resources to support line clearance and reduced the work completed. This work must be completed on an ongoing basis to avoid negative service level impacts, and 2006 funding is adjusted to address this. Furthermore, there is an increase in 2006 line clearance spending to improve reliability and reduce pockets of customers experiencing frequent outages. This plan for line clearance is critical to both planned productivity improvements and PEP savings.

1 **Q. What are the Storm costs, Lines 3 and 8?**

2 A. Storm costs are the required expenses to restore the electrical system
3 typically after significant weather events. These costs are distributed to
4 their respective operation and maintenance Line items. Although some
5 years experience more or less storms than others, the average across
6 several years is used to level out this variability. 2005 was not an unusual
7 year with respect to historical averages.

8

9 **Q. Explain the “Other” Distribution Operations and Maintenance costs.**

10 A. The “Other” cost identified in Lines 4 and 9 include those areas not
11 otherwise specifically identified, but broken into the categories Maintenance
12 and Operations. The “Other” costs for Maintenance fall into two main
13 categories, system maintenance and daily outage restoration. The “Other”
14 costs for Operating include the expense to operate the electrical system for
15 safety and repair work, the costs for the support of all areas, and the costs
16 for training. Detroit Edison’s recent training programs have been very
17 successful in improving safety and resulted in a 38% reduction in
18 Distribution Operation’s OSHA Recordable Rate.

19

20 **Q. Please explain the Electric Choice expenses shown on Line 11, Exhibit**
21 **DE-16, Schedule F5-3.**

22 A. The operating expenses for Electric Choice reflect the areas of Customer
23 Transactions, Supplier Transactions, and Program Management. Each of
24 these categories is necessary for the continued operation of the Electric

1 Choice program.

2

3 The Customer Transaction and Supplier Transaction charges are forecasted
4 to remain stable through 2008, except for inflation adjustments.

5

6 The Program Management expenses, including the cost of information
7 systems and data acquisition, are forecasted to decrease. Remaining
8 information system development is scheduled for 2006, with some work
9 finishing in 2007. The remaining expenses in this area relate to the
10 maintenance and ongoing production support of the systems developed for
11 Electric Choice. The total expense for Program Management will continue
12 decreasing due primarily to the transition of work from the implementation of
13 the program to a process management function. Adjustments for this are
14 included in the known and measurable section.

15

16 **Q. Can you please describe Line 13, Inflation Adjustment?**

17 A. This Line applies the inflation described in Exhibit DE-16, Schedule F1-1
18 starting with Line 12, Total in 2005 to project needed O&M from 2006 to
19 2011 without known and measurable adjustments.

20

21 **Q. Can you please describe what O&M savings are associated with PEP,**
22 **Line 15?**

23 A. Reduction of storm and other costs associated with increased reliability
24 spending is a major component of the O&M savings. Without the increased

line clearance, Line 19 of Exhibit DE-16, Schedule F5-3 and capital efforts, Line 43 of Exhibit DE-16, Schedule F3-5, these savings will be significantly reduced.

Q. What impact will the Company's AMR system have on the O&M budget?

A. AMR will provide automated outage detection that will reduce the number of times a crew is sent to complete customer restoration when no outage exists. AMR will also provide load monitoring information to better support identification of overloaded distribution transformers for proactive replacement. This proactive replacement will reduce replacement on overtime, reduce outages and low voltage issues and prevent the need for spill cleaning. Reduced travel time spent on power quality monitoring information will also result. This impact is included on Line 17 of Exhibit DE-16, Schedule F5-3.

Q. What is the Pole Attachment Expense, Line 18?

A. Between 1994 and 2001, the number of poles and the rate used to calculate the payment for pole attachments between Detroit Edison and one major joint user was maintained constant. This impacted both revenue collected by Detroit Edison and the expense Detroit Edison paid to attach to the poles owned by the joint user. In 2001, Detroit Edison attempted to adjust the pole count and rate to more accurately reflect reality and contractual terms. This resulted in a significant change in collections and expenses. A court

case was initiated to conclude this matter and was settled by jury verdict in August 2005. The adjustment on Line 18 of Exhibit DE-16, Schedule F5-3 reflects the impact on expenses.

Q. Please explain the Line Clearance Increased Reliability adjustment, Line 19.

A. As previously described, the restoration efforts required due to hurricanes in the southern states drew resources out of Detroit Edison's service territory, including those needed to support line clearance. The work not completed must be accomplished on an ongoing basis to avoid degrading customer satisfaction levels. The cost to complete this work is included in the line clearance adjustment, as well as the funding needed to support the Company's increase in reliability efforts to improve SAIFI and reduce pockets of customers experiencing frequent outages. Line clearance is a key aspect of this, and this Line is to account for these increased efforts. This is a key aspect of realizing PEP savings.

Q. In your opinion, are the actual and projected "Energy Delivery O&M Expense 2005 - 2011" shown in Exhibit DE-16, Schedule F5-3 for the years 2005 through 2011 reasonable?

A. Yes, they are. I base my opinion on analysis of past expenses, projected requirements for labor and material for the safe and reliable distribution of electric power and the need to meet Company goals for improving customer service.

1

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

3 A. Yes, it does.