

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
SKILES W. BOYD

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF SKILES W. BOYD

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1 **Q. What is your name, title and business address, and by whom are you**
2 **employed?**

3 A. My name is Skiles W. Boyd. I am employed by The Detroit Edison
4 Company as Vice President of Environmental Management and Resources.
5 My business address is The Detroit Edison Company, 2000 Second
6 Avenue, Detroit, Michigan 48226.

7

8 **Q What is your educational background?**

9 A I have a Bachelors of Science in Environmental Resource Management
10 from the Pennsylvania State University and an MBA from Wayne State
11 University.

12

13 **Q. What is your work experience at Detroit Edison?**

14 A. I have been employed by Detroit Edison for 28 years, all in environmental
15 work. I have progressed from Associate Engineer to Senior Engineer, to
16 Principal Engineer, to Administrator Hazardous and Toxic Programs, to
17 Director and, most recently, to Vice President.

18

19 **Q. What does your present position encompass?**

20 A. As Vice President of Environmental Management and Resources, I manage
21 an organization of approximately 80 people involved with: 1) the
22 development and interpretation of environmental laws, regulation and policy;
23 2) working with Detroit Edison's operating organizations to implement
24 programs to comply with those requirements; 3) permitting activities; 4)
25 interfacing with federal, state and local environmental agencies, and other

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1 stakeholders; 5) conducting environmental studies and implementing
2 actions to ensure compliance of company facilities with environmental
3 requirements; and 6) conducting environmental audits and reporting both
4 internally and externally where appropriate. In addition, my organization is
5 tasked, in conjunction with other Detroit Edison organizations, with
6 developing, recommending and directing the implementation of strategies to
7 cost effectively comply with the numerous environmental requirements in a
8 cost-effective manner.

9

10 **Q. Are you involved in any organizations other than Detroit Edison?**

11 A. Yes, throughout my career, I have worked with the Detroit Chamber of
12 Commerce, Michigan Chamber of Commerce, Michigan Manufacturers
13 Association (MMA), the Edison Electric Institute (EEI), the Electric Power
14 Research Institute (EPRI) the Air and Waste Management Association
15 (AWMA) and various other industry and other stakeholder groups to help
16 accomplish the functions stated previously. I presently serve as Vice
17 Chairman of the EEI Executive Environmental Advisory Council.

18

19 **Q. Have you published articles or do you speak at Conferences?**

20 A. Yes, I have periodically been a contributor to published articles and have
21 periodically spoken at various industry and other sponsored environmental
22 conferences.

23

24 **Q Have you testified previously before this Commission?**

25 A I have not previously testified in any formal rate making process before this

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1 Commission. I have, however, testified in legislative and regulatory
2 hearings on environmental matters.

THE DETROIT EDISON COMPANY
DIRECT TESTIMONY OF SKILES W. BOYD

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

2 A. The purpose of my testimony is to support the corporate environmental
3 compliance strategy and the necessity and reasonableness of the capital
4 expenses required by the Company to comply with Nitrogen Oxides (NO_x),
5 Sulfur Dioxide (SO₂), and mercury emission reduction requirements of the
6 NO_x SIP Call developed from 1998 through 2003, the Clean Air Interstate Rule
7 (CAIR) issued in 2005, and the Clean Air Mercury Rule (CAMR), also issued
8 in 2005. This includes both capital expenses incurred to date and expected
9 capital expenses going forward through 2011. I will provide background on
10 the applicable regulations, detail regarding the Company's strategy to comply
11 with these regulations, and detail regarding the costs of implementing this
12 strategy.

13

14 **Q. Are you sponsoring any exhibits in support of your testimony?**

15 A. Yes, I am sponsoring Exhibit DE-16, Schedule F3-4 entitled "Capital
16 Expenditures – Environmental 2005 – 2011".

17

18 **Q. Was this exhibit prepared by you or under your direction?**

19 A. Yes.

20

21 **Q. Can you summarize current environmental regulations?**

22 A. Yes. As a result of U S Environmental Protection Agency (EPA)
23 rulemaking, Detroit Edison has undergone significant change in air emission
24 regulations. EPA has developed regulations requiring electric utilities to
25 further reduce Nitrogen Oxide (NO_x) and Sulfur Dioxide (SO₂) emissions. In

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1 addition, EPA has promulgated the first ever rule which requires electric
2 generating units (EGUs) to reduce emissions of mercury. These
3 requirements represent significant expenditures by Detroit Edison. These
4 expenditures began in 1998 and will continue beyond 2011.

5

6 NO_x SIP Call Requirements

7 Beginning in 1998 and continuing through 2003, EPA developed and
8 implemented rules (commonly referred to as the NO_x State Implementation
9 Plan (SIP) Call) which resulted in a 65% reduction requirement for NO_x
10 emissions by 2004 for Electric Generating Units (EGUs) located in a
11 geographic region that includes 22 Eastern States (including Michigan) and
12 the District of Columbia. For Detroit Edison, this represents an ozone
13 season (May through September) NO_x reduction each year of over 31,000
14 tons from historic levels. These rules include a market based “cap and
15 trade” component that allows affected sources to comply by either installing
16 NO_x emission reduction technology or by purchasing excess allowances
17 from a market supplied by those who may reduce beyond the actual
18 reduction requirements.

19

20 Detroit Edison has pursued a compliance strategy that includes installation
21 of technology-based NO_x emission controls along with the purchase of
22 emission allowances. In doing so, Detroit Edison evaluated a number of
23 proven NO_x emission reduction technologies and identified a combination of
24 applications for its EGU portfolio that would safely and reliably provide the

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1 necessary reductions at least cost. The Company's NO_x emission
2 compliance strategy includes the installation of both combustion and post
3 combustion technologies on numerous units within the portfolio, beginning
4 in 1999 and continuing through 2011.

5

6 Clean Air Interstate Rule

7 In addition to the NO_x emission reduction requirements of the NO_x SIP Call,
8 the Company will be further impacted by additional emission reduction
9 requirements going forward. On March 10, 2005, EPA issued the Clean Air
10 Interstate Rule (CAIR). CAIR permanently caps annual emissions of sulfur
11 dioxide (SO₂) and nitrogen oxides (NO_x) in the eastern United States. CAIR
12 achieves large reductions of SO₂ and/or NO_x emissions across 28 eastern
13 states (including Michigan) and the District of Columbia. When fully
14 implemented, CAIR will reduce SO₂ emissions in these states by over 70
15 percent and NO_x emissions by over 60 percent from 2003 levels.

16

17 Detroit Edison has continued to develop and modify a compliance strategy
18 based on the original NO_x SIP Call compliance strategy. The compliance
19 strategy builds on the original technology-based NO_x emission controls,
20 adding economical SO₂ controls along with participation in developing
21 emission allowance markets.

22

23 Clean Air Mercury Rule

24 A closely related action is the EPA Clean Air Mercury Rule (CAMR), the first

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1 ever federally-mandated requirement that coal-fired electric utilities reduce
2 their emissions of mercury. CAMR, issued by EPA on March 15, 2005,
3 builds on EPA's Clean Air Interstate Rule (CAIR) to significantly reduce
4 emissions from coal-fired power plants. When fully implemented, these
5 rules will reduce annual utility emissions of mercury nationally from 48 tons
6 a year to 15 tons, a reduction of nearly 70 percent. Issuance of CAMR
7 marks the first time EPA has regulated mercury emissions from utilities, and
8 makes the U.S. the first nation in the world to control emissions from this
9 major source of mercury.

10

11 The Detroit Edison compliance plan maximizes the use of NO_x and SO₂
12 controls to reduce mercury emissions. These "co-benefit" reductions
13 represent the least-cost mercury reductions, since the control equipment is
14 installed to target reductions in other pollutants. While EPA has proposed a
15 cap and trade program for the CAMR implementation, the State of Michigan
16 is currently pursuing rulemaking that may not allow emission trading for
17 mercury. The final rulemaking will have a profound impact on the ultimate
18 compliance requirements and the Detroit Edison strategy for mercury
19 emission compliance.

20

21 **RECENT ENVIRONMENTAL REGULATORY BACKGROUND**

22 **Q. What regulations currently govern emissions of Nitrogen Oxides from**
23 **Detroit Edison EGUs?**

24 **A.** A number of regulations currently control emissions of nitrogen oxides (NO_x)

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1 from Detroit Edison's EGUs. On the Federal level, they include the Acid
2 Rain Program (Title IV of the Clean Air Act Amendments of 1990 (CAAA)),
3 the NO_x SIP Call and CAIR. On the State level, Michigan Part 8 Rules
4 regulate NO_x emissions from the Company's EGUs.

5

6 **Q. Please describe the NO_x requirements of the Acid Rain Program.**

7 A. The Acid Rain Program set NO_x standards for emissions from utility sources
8 with a goal of reducing 1980 level emissions by 2 million tons by the year
9 2000. Specifically, NO_x emission reduction requirements, defined in Part 76
10 of Title IV of the CAAA, outline a phase-in approach to NO_x emission rate
11 limits for various boiler designs. The second phase, which included all of
12 the Detroit Edison coal-fired boilers, required NO_x emission rate reductions
13 by 2000. The program included a "results oriented" compliance approach
14 that allowed compliance on a portfolio level rather than by individual source.
15 This unique approach was designed to allow EGU owner/operators flexibility
16 in meeting the requirements, potentially in a more cost effective manner.

17

18 **Q. With respect to the Acid Rain Program defined in Title IV of the CAAA,**
19 **what NO_x emission reductions were required of Detroit Edison?**

20 A. The Company utilized the portfolio level compliance approach included in
21 Part 76 to comply with the NO_x emission requirements of Title IV. As a
22 result, the Company was required to reduce its portfolio average annual
23 NO_x emission rate from 0.83 lbs/mmBtu to 0.52 lbs/mmBtu.

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1 **Q. How did Detroit Edison comply with the NO_x emission reductions**
2 **required by the Acid Rain Program?**

3 A. The Company determined that the most effective way to comply with the
4 NO_x emission requirements outlined in Title IV was to install Low NO_x
5 Burner (LNB) technology on the four boilers at the Monroe Power Plant.
6 These burner modifications were installed between 1994 and 1996.

7

8 **Q. Will you please describe the NO_x SIP Call requirements?**

9 A. In October 1998, the EPA finalized the "Finding of Significant Contribution
10 and Rulemaking for Certain States in the Ozone Transport Assessment
11 Group Region for Purposes of Reducing Regional Transport of Ozone"
12 (Commonly called the NO_x SIP Call). The NO_x SIP Call expanded on the
13 "results oriented" portfolio level compliance approach included in Title IV by
14 including a full market-based approach to compliance. The EPA introduced
15 a model NO_x Budget Trading Program rule (Part 96 of Title I) as guidance
16 for those States opting to meet the requirements of the NO_x SIP Call
17 through an allowance-trading program (commonly called a cap and trade
18 program). This trading program was developed to facilitate cost effective
19 NO_x emissions reductions from large stationary sources. States choosing to
20 participate in the NO_x Budget Trading Program have the flexibility to modify
21 certain provisions within the model rule as they develop their respective
22 SIPs.

23

24 **Q. Will you please describe the cap and trade component of the NO_x SIP**

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1

Call in more detail?

2

A. Traditionally, emission control regulations have utilized set limits (or rates) by which each source was measured. Cap and trade differs from the traditional approach by providing operational and economic flexibility to the participating sources with the intent of minimizing overall compliance costs.

6

7

In administering the cap and trade approach, the EPA first set a total allowable emission level (in tons) for a given compliance period and geographic region. The total emissions level is called the “cap”. The geographic region defined in the NO_x SIP Call includes 22 states (including Michigan) and the District of Columbia and the compliance period is May through September (commonly called the ozone season). The EGU NO_x emission cap for the region was set to require an approximate 65% reduction in historic NO_x emissions.

15

16

The overall cap was then divided and allocated to each State within the region based on criteria defined by the EPA. These allocated amounts became the NO_x emission tonnage budgets that each State was required to meet via an EPA approved SIP. Each SIP further divides and allocates the State budget by assigning allowances (in tons) to each affected source of NO_x emissions, which in turn becomes a NO_x emissions budget for that source. In the end, the sum total of the budget allowances for each NO_x source will be equal to or less than the cap for the entire region.

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1 During the ozone season, sources are required to measure, report, and
2 certify all NO_x emissions. Sources achieve compliance by having enough
3 emission allowances to cover the actual emissions for the period. If a
4 source emits less than the number of emission allowances it has in hand, it
5 can either sell the excess emission allowances in the open market or bank
6 them for future consumption. Sources that emit more than the number of
7 allowances in hand must purchase the required balance from the market. In
8 doing so, the “cap and trade” program provides an incentive to optimize
9 economic resources between sources in the region, reduce overall
10 compliance costs, while still achieving compliance.

11

12 **Q. How did Michigan respond to the NO_x SIP Call?**

13 A. The Michigan Department of Environmental Quality (MDEQ) commenced a
14 rulemaking process using a Stakeholders Workgroup to develop a SIP that
15 was consistent with the NO_x SIP Call, including a deadline for full
16 implementation of EPA approved SIPs by May 31, 2004. The resulting
17 Michigan Part 8 Rules, promulgated on December 4, 2002, included Rules
18 802 through 818, which comprise Michigan’s response to EPA’s NO_x SIP
19 Call.

20

21 **Q. How did Detroit Edison comply with the NO_x emission reductions**
22 **required by the NO_x SIP Call?**

23 A. The company determined that the most effective way to comply with the
24 NO_x emission reduction requirements mandated by the NO_x SIP Call

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1 included a combination of technology based controls and participation in the
2 emission allowance market.

3

4 **Q. Will you please describe the CAIR requirements?**

5 A. In addition to the NO_x emission reduction requirements of the NO_x SIP Call,
6 the Company will be further impacted by additional emission reduction
7 requirements going forward. On March 10, 2005, EPA issued CAIR. CAIR
8 permanently caps annual emissions of sulfur dioxide (SO₂) and nitrogen
9 oxides (NO_x) in the eastern United States. CAIR achieves large reductions
10 of SO₂ and/or NO_x emissions across 28 eastern states (including Michigan)
11 and the District of Columbia. When fully implemented, CAIR will reduce
12 SO₂ emissions in these states by over 70 percent and NO_x emissions by
13 over 60 percent from 2003 levels.

14

15 **Q. Does CAIR regulate emissions beyond NO_x?**

16 A. Yes. CAIR will require NO_x emission reductions beyond those required by
17 the NO_x SIP Call by also mandating emission reductions in the non-ozone
18 season, but it also requires significant reductions in SO₂ emissions.

19

20 **Q. Are the final emission reduction requirements imposed by CAIR well**
21 **understood?**

22 A. No, not completely. As with the NO_x SIP Call regulatory process, EPA has
23 defined the reductions required by each affected state and recommended a
24 model rule which includes reductions from electric generating units using a

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

7

8 **Q. How did Michigan respond to CAIR?**

9 A. As with the NO_x SIP Call, the MDEQ commenced a rulemaking process
10 using a Stakeholders Workgroup to develop a Rule that is consistent with
11 the CAIR reduction requirements. The rulemaking process is still ongoing,
12 so the final requirements affecting Detroit Edison EGUs are still uncertain.

13

14 **Q. How will Detroit Edison comply with the NO_x and SO₂ emission**
15 **reductions required by CAIR?**

16 A. Based on the EPA's proposed CAIR reduction requirements, Detroit Edison
17 has continued to develop and modify a flexible emission compliance strategy
18 based on the original NO_x SIP Call compliance strategy. The emission
19 compliance strategy builds on the original technology-based NO_x emission
20 controls, adding cost-effective SO₂ emission controls along with economical
21 participation in developing emission allowance markets.

22

23 **Q. Will you please describe CAMR?**

24 A. On March 15, 2005, EPA issued CAMR to permanently cap and reduce

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1 annual mercury emissions from all coal-fired power plants in the United
2 States. This rule makes the United States the first country in the world to
3 regulate mercury emissions from utilities. Together the CAMR and CAIR
4 create a multi-pollutant strategy to reduce emissions throughout the United
5 States.

6

7 **Q. How does the CAMR propose to regulate mercury?**

8 A. CAMR establishes “standards of performance” limiting mercury emissions
9 from new and existing coal-fired power plants and creates a market-based
10 cap and trade program that will reduce nationwide utility emissions of
11 mercury in two separate phases. The 2010 first phase cap is 38 tons and
12 emissions will be reduced primarily by taking advantage of “co-benefit”
13 reductions. Co-benefit reductions are mercury reductions that occur by
14 installing and operating emission control technology to reduce sulfur dioxide
15 (SO₂) and nitrogen oxides (NO_x) emissions to meet CAIR requirements. In
16 the second phase, due in 2018, coal-fired power plants will be subject to a
17 more restrictive cap, which will reduce emissions to 15 tons upon full
18 implementation.

19

20 **Q. Has Michigan begun to develop rules to implement CAMR?**

21 A. Only on a very preliminary basis. On April 17, 2006, Governor Jennifer
22 Granholm announced a proposal to reduce mercury emissions from
23 Michigan power plants. Under the Governor’s directive, the MDEQ is to
24 develop a rule that will require Michigan power plants to reduce mercury
25 emissions by 90 percent, exceeding EPA’s CAMR requirements, by 2015

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1 based on a system-wide approach. The Governor directed that this rule
2 should not allow interstate trading, but that under certain conditions, it could
3 include a utility system-wide approach. The MDEQ has held one
4 information meeting and is expected to soon begin working on promulgating
5 the rule by initiating a formal stakeholder group process to implement the
6 Governor's directive.

7

8 **Q. How will Detroit Edison comply with the mercury reductions required**
9 **by CAMR?**

10 A. Until the Governor's announcement on April 17, Detroit Edison had developed
11 a compliance plan based on the EPA's proposed CAMR emission reduction
12 requirements. This strategy was an approach that maximizes mercury co-
13 benefits from SO₂ and NO_x emission reduction technology installations, with
14 flexibility to adjust to final rule requirements and emission allowance market
15 conditions. This strategy will potentially require significant additions in
16 response to a final Michigan rules package. However, the mercury reductions
17 planned that maximize mercury co-benefits from SO₂ and NO_x emission
18 reduction technology installations will continue to play an important, and now
19 even more necessary part.

20

21 **Q. Is Detroit Edison facing any other major environmental regulatory**
22 **requirements?**

23 A. Yes. EPA has developed regulations under section §316(b) of the Clean
24 Water Act. §316(b) requires that the location, design, construction and
25 capacity of cooling water intake structures reflect the best technology

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1 available for minimizing adverse environmental impact. The new rule
2 requires all large existing power plants to meet performance standards to
3 reduce the number of organisms pinned against parts of the cooling water
4 intake structure by 80 to 95 percent. Depending on location, the amount of
5 water withdrawn, and energy generation, certain facilities will also have to
6 meet performance standards to reduce the number of aquatic organisms
7 drawn into the cooling system by 60 to 90 percent. These ranges represent
8 differences among facilities and nearby aquatic environments. To offer
9 these large power plants flexibility to comply and to ensure energy reliability,
10 facilities will have several compliance alternatives to meet the performance
11 standards. The alternatives include using existing technologies, selecting
12 additional fish protection technologies (such as screens with fish return
13 systems), and using restoration measures.

14

15 **Q. How is this expected to affect Detroit Edison?**

16 A. The rule is being implemented through the State of Michigan's National
17 Pollutant Discharge Elimination System permit program. Extensive
18 information (results of biological studies, engineering design work and
19 economic analyses) must be submitted to ensure compliance with the rule.
20 The Company has conducted required extensive biological studies at the
21 Monroe, Trenton Channel, River Rouge, Conners Creek, St. Clair, Belle
22 River and Harbor Beach power plants and is currently evaluating the results.
23 Alternatives for complying with the rule will be finalized using the results of
24 the biological studies, engineering evaluations and economic analyses.

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1 Preliminary estimates of compliance costs range up to \$50 million
2 distributed over 5 to 8 years beginning in 2005.

3

4 **EMISSION REDUCTION REQUIREMENT ALTERNATIVES**

5 **Q. In order to achieve the required level of NO_x, SO₂ and mercury**
6 **emission reductions, what strategic options exist for Detroit Edison?**

7 A. In theory, five possibilities exist. 1) unit shutdown and/or unit output
8 reduction, 2) fuel switching, 3) purchase of emission allowances from the
9 markets to offset actual emissions, 4) install NO_x, SO₂ and mercury
10 reduction equipment to reduce emissions, 5) any combination of the four
11 items listed above.

12

13 **Q. In developing an emission reduction strategy involving these**
14 **alternatives, what factors should be considered?**

15 A. Each alternative has a unique set of risks and associated costs. In
16 identifying the best overall compliance strategy, a company must evaluate
17 each alternative with respect to cost and ability to achieve the required level
18 of emission reductions. Cost comparisons of various compliance
19 alternatives can be made on a \$/ton of NO_x and SO₂ and \$/pound of
20 mercury reduced basis. In addition to reduction levels and cost aspects, a
21 Company must develop a strategy that is flexible with respect to
22 implementation timing given the regulatory uncertainties that may exist at
23 the time that strategic decisions are required.

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1 Specifically with respect to option number 1 above, unit shutdown and/or
2 reduced unit output would indeed reduce emissions. However, significant
3 system reliability concerns would result from lost capacity, especially during
4 peak periods. Additionally, the amount of ozone season and annual NO_x
5 emission allowances allocated to each unit under the NO_x SIP Call and
6 CAIR is redistributed every three years based on actual unit heat input. If
7 compliance to a cap and trade oriented NO_x emission reduction program is
8 achieved by reducing output or shutting a unit(s) down, future emission
9 allowances for those generating units are either reduced or eliminated. In
10 turn this would require additional output reductions and/or more shutdowns.
11 In the end, this is not a sustainable compliance strategy.

12

13 Fuel switching, such as replacing coal with natural gas, would provide
14 emission reductions, but at an unreasonable increased fuel cost. Fuel
15 switching, as identified in option 2 however, was used extensively for
16 compliance with the Acid Rain SO₂ reduction requirements. Detroit Edison
17 has aggressively approached maximizing the economical use of lower sulfur
18 coal. Wherever possible, the Company's EGUs economically blend low,
19 mid, and high sulfur eastern coals with low sulfur western coals. System
20 load requirements, equipment capabilities, environmental regulations, and
21 economics are used to determine the appropriate blend. Low sulfur western
22 coal use is maximized based upon the above-mentioned variables with
23 higher sulfur eastern coal used in the remaining portion of the coal blend.
24 The higher sulfur coals are needed to optimize precipitator performance.

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1 The higher heating values that are generally characteristic of the higher
2 sulfur coals purchased by the Company are also needed to optimize boiler
3 and boiler related equipment performance. Therefore, the replacement of
4 higher sulfur eastern coals with lower sulfur eastern coals can come at the
5 expense of decreased low sulfur western coal use and increase the overall
6 system fuel expense based upon the forecasted system load requirements,
7 coal costs, and SO₂ emission allowance costs.

8

9 As for option number 3, buying emission allowances from the marketplace
10 to offset excess emissions for a company's entire generating portfolio would
11 require the purchase of a large amount of allowances in new and
12 undeveloped markets. The amount of allowances available in the
13 marketplace is a function of whether various companies decide to over-
14 control by installing more emission reduction technology than is required to
15 achieve initial compliance. To the extent over-control does not occur,
16 allowances may not be available to purchase at any price, resulting in unit
17 shutdown as the only remaining economic and compliant alternative in the
18 short term. To the extent over-control does occur, the risk of high allowance
19 prices could result as companies that are long on emission allowances
20 extract maximum value from those companies that are short. Since there is
21 no guarantee that the required volume of allowances would be available (at
22 any price), a market only based compliance option was considered
23 extremely risky.

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1 With respect to option number 4, achieving compliance by installing
2 emission reduction technology and actually reducing emissions does not
3 carry the electric system reliability risks of option number 1 and has
4 significantly less economic risk than option number 3. Nonetheless, a
5 company employing this option is challenged with identifying the mix of
6 technology applications that achieves the required reduction levels at least
7 cost. This is a complex and somewhat uncertain analysis given the
8 regulatory uncertainties discussed above, the multi-pollutant reduction
9 requirements, and timing of the decisions required to employ particular
10 technology options. In addition, if the entire region over-controls with
11 emission control technology installations, the emission allowance price
12 could fall below the price of available emission allowances. A company
13 must therefore not only analyze it's own application of technology options,
14 but the market impact of emission control technology installations across the
15 entire regulated community to ensure the cost of technology installations are
16 below forecasted emission allowance market prices..

17

18 Finally, as to option number 5, any combination strategy carries risk for the
19 same reasons outlined in options 3 and 4 above. Without developed,
20 robust, liquid markets for emission allowances, economic and compliance
21 risk from this option needs to be mitigated by limiting exposure to the
22 market. With large amounts of allowance purchases required, there is
23 significant exposure to allowance price volatility and limited availability. In
24 order to minimize exposure to market prices, a company can purchase

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1 enough allowances to cover compliance in advance of the period of time
2 required for installation of emission control technology. In addition, the
3 various allowance markets provide a hedge opportunity in the event
4 technology doesn't perform as expected or costs rise for various reasons
5 that cannot be prevented. This provides an effective hedge for compliance
6 against market and technology uncertainty.

7

8 **Q. Which emission reduction strategy did Detroit Edison choose?**

9 A. After evaluating the various alternatives described above, the Company
10 chose to employ a combination of technology-based and allowance market
11 approach similar to option number 5 above. The original strategy was
12 developed in 1998 for NO_x SIP Call compliance and has been expanded to
13 effectively include expected reduction requirements of annual NO_x, SO₂ and
14 mercury. The compliance strategy has maintained enough flexibility to
15 manage the tradeoffs between these regulatory, market, and technological
16 risks in order to minimize the cost of compliance. With regulations not
17 completely finalized and the emission allowance markets continuing to
18 develop, the potential for further plan adjustments and cost changes remain.

19

20 This strategy also appears to be consistent with that used by most other
21 major utilities. Emission control technologies are employed where cost-
22 effective, and the allowance markets are developing liquidity as utilities use
23 them to either purchase allowances to make up for shortfalls, or to sell
24 excess allowances to offset control technology costs. Based on the

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1 effectiveness of the Detroit Edison NO_x strategy, we are confident that the
2 existing strategy, with modifications to include SO₂ and mercury reductions,
3 is sound.

4

5 **Q. Will you please describe the various NO_x reduction technology**
6 **alternatives that were evaluated by the Company in determining the**
7 **compliance plan?**

8 A. Many NO_x reduction technologies exist and include both combustion and
9 post-combustion alternatives. The Company evaluated both combustion
10 and post-combustion technologies prior to determining the mix that provided
11 the required NO_x emission reductions for the least overall cost. Of the
12 technologies considered, several significant ones are described below. They
13 include Combustion Optimization (CO), Low NO_x Burners (LNB), Over-Fire
14 Air (OFA), and Selective Catalytic Reduction (SCR), natural gas conversion,
15 reburn technology, and selective non-catalytic reduction (SNCR).

16

17 **Q. Will you please describe Combustion Optimization (CO) technology?**

18 A. CO is a combustion related technology that involves installation of
19 sophisticated boiler controls that minimize the presence of excess air in the
20 furnace, thereby reducing NO_x formation. In addition, CO is a useful
21 combustion monitoring tool that allows a boiler operator to sustain
22 improvements gained through other combustion technologies, such as LNB
23 and OFA. CO can achieve NO_x reductions of 5% to 20% depending on
24 boiler design and fuel type. The cost of CO ranges from \$100,000 to

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1 \$500,000 per unit depending on the level of sophistication.

2

3 **Q. Will you please describe Low NO_x Burner (LNB) technology?**

4 A. LNB is a combustion related technology that involves the modification or
5 replacement of existing coal burners on the boiler. As opposed to a
6 traditional coal burner, LNB minimizes turbulent mixtures of coal and
7 combustion air as it enters the furnace, thereby slowing the rate of
8 combustion. The slower rate of combustion results in a larger, lower
9 temperature fireball, thereby reducing NO_x formation. The NO_x reduction
10 efficiency and cost is somewhat dependent on boiler design and fuel type.
11 Low NO_x Burners can achieve NO_x reductions of 20% to 40% at a cost
12 range of \$20 to \$40/kW.

13

14 **Q. Will you please describe Over-Fire Air (OFA) technology?**

15 A. OFA is also a combustion related technology that stages the combustion of
16 coal to reduce NO_x formation in the furnace. First, a "fuel-rich" combustion
17 environment is generated in the lower furnace by reducing the quantity of air
18 delivered to the burners. Second, supplemental combustion air is
19 introduced through ports installed above the existing coal burners. This
20 combustion staging results in lower flame temperatures, lower levels of free
21 oxygen for combustion, and reduced NO_x formation. Generally, OFA is
22 installed in concert with LNB to enhance LNB performance. When installed
23 with LNB, NO_x reductions in the range of 30% to 60% can be achieved.
24 OFA can be installed at an incremental cost of approximately \$10/kW when

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1 installed with LNB.

2

3 **Q. Will you please describe Selective Catalytic Reduction (SCR)**
4 **technology?**

5 A. SCR is a post-combustion technology that converts the NO_x formed in the
6 boiler to nitrogen gas and water vapor. This reaction occurs in the presence
7 of ammonia, which is injected into the flue gas stream as part of the
8 process. A catalyst is used to increase the efficiency and completeness of
9 the reaction at the temperatures normally realized in the flue gas stream.
10 SCR is the most efficient NO_x reduction technology available and can
11 achieve a NO_x removal rate of 80% - 90%, depending on catalyst
12 performance and ammonia injection rates. It is also the most expensive at a
13 range of \$60/kW to over \$250/kW. This wide range results from a number
14 of variables associated with boilers of varying size, design, and layout.
15 These variables include the costs associated with installation and/or
16 modification of support structure, ductwork, catalyst beds, induced draft
17 fans, and other support components. Another significant cost variable for
18 SCR (and other technologies that require ammonia), relates to the chemical
19 delivery system required for storage and delivery of ammonia to the flue gas
20 stream.

21

22 **Q. Will you please describe Gas Conversion?**

23 A. Gas conversion refers to fuel switching from coal to natural gas. Although a
24 full Gas Conversion system could potentially provide the required NO_x (in

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1 addition to SO₂ and mercury) emission reductions, the fuel cost would be
2 significantly increased. In addition, conversion from coal to natural gas
3 requires extensive and costly boiler modifications in order to maintain the
4 steam production capability normally achieved with coal. In the end, this is
5 not an economic alternative for NO_x reduction on a large coal based
6 generation asset portfolio, such as that of Detroit Edison.

7

8 **Q. Will you please describe Reburn technology?**

9 A. Similar to OFA, Reburn Technology is a combustion-related technology that
10 stages the combustion in the furnace, although in a different way.
11 Reburning requires the injection of some fraction (typically 10-30%) of the
12 fuel input into the upper furnace through ports located above the primary
13 combustion zone. Natural gas is typically the reburn fuel of choice because
14 it results in reductions in particulate matter, SO₂, and CO₂ emissions, in
15 addition to NO_x. The Company also evaluated pulverized coal, micronized
16 coal (<50 microns), fuel oil, and Orimulsion as reburn fuels. This technology
17 can potentially reduce NO_x emissions by 10% to 30% but, due to the
18 additional expense associated with the alternate fuels, this option proved to
19 be uneconomic.

20

21 **Q. Will you please describe Selective Non-Catalytic Reduction (SNCR)**
22 **technology?**

23 A. Similar to SCR, SNCR is a post-combustion control technology that involves
24 the injection of ammonia (or urea) into the flue gas stream where it reacts

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1 with NO_x to form nitrogen and water vapor. However, SNCR differs from
2 SCR in that it does not utilize a catalyst, thereby significantly increasing
3 ammonia usage and associated operating costs. The gas temperature at
4 the point of injection is critical to the NO_x reduction performance of an
5 SNCR system. Since the temperature profile in the flue gas stream
6 changes with changes in boiler load, the optimum injection point changes
7 and multiple injection points are required. However, most large utility boilers
8 have heat transfer surfaces (pendants and platens) positioned in this flue
9 gas temperature zone. This will reduce the effectiveness of the SNCR
10 system, even if multiple injection levels are installed. In some cases, these
11 internal obstructions make the application of SNCR impractical. Emission
12 reduction capabilities range from 20% to 30% at an installed cost range of
13 \$10 to \$30/kW.

14

15 **Q. Will you please describe the various SO₂ reduction technology**
16 **alternatives that were evaluated by the Company in determining the**
17 **compliance plan?**

18 A. Aside from fuel switching as discussed earlier, SO₂ reduction is achieved
19 with post-combustion controls. Controls fall under the category of Wet Flue
20 Gas Desulfurization (FGD) or Dry (or semi-dry) FGD.

21

22 **Q. Will you please describe Wet FGD?**

23 A. Wet FGD, or scrubber, is typically a wet slurry system, where wet limestone
24 slurry is contacted with flue gas providing 95% or better SO₂ removal. A

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1 typical spray tower design would spray the slurry downward through a
2 series of headers and nozzles and scrubs the flue gas as it moves upward
3 through the tower. The slurry can become a waste product that must be
4 landfilled, or with proper FGD design, can be converted into usable
5 synthetic gypsum. Since this is a wet process, the flue gas exits the
6 absorber in the saturated condition. This requires a stack design that is
7 considerably different than most dry stacks.

8

9 **Q. Will you please describe Dry FGD?**

10 A. Dry FGD systems typically use a spray dry absorber (SDA) to bring the hot
11 flue gas into contact with atomized lime slurry. A chemical reaction results
12 in the removal of acid gases and the simultaneous evaporation of water.
13 The cooled and treated flue gas exits the SDA and is passed through a
14 particulate collector, which is typically a fabric filter. Since the gas exits the
15 spray dryer above saturation temperature, the existing stack can typically be
16 used in a retrofit.

17

18 **Q. Will you please describe the various mercury reduction technology**
19 **alternatives that were evaluated by the Company in determining the**
20 **compliance plan?**

21 A. Mercury-specific controls applicable to EGUs are still in the development
22 stage. Considerable testing done by the United States Department of
23 Energy (US DOE), EPA, and electric utilities have identified that the use of
24 sorbents injected upstream of a boiler's particulate control device has the

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1 potential to be effective in mercury control. In addition, some SO₂ controls
2 have shown to be effective in certain circumstances to provide some
3 mercury reduction in addition to the SO₂ they were designed to remove.
4

5 **Q. Will you please describe sorbent injection for mercury control?**

6 A. Injecting a sorbent into the flue gas stream in front of a particulate device
7 has provided some level of mercury reduction. Under most conditions, if a
8 suitably selected sorbent achieves good contact with the gaseous mercury
9 for a sufficient amount of time, it will absorb mercury. There are many
10 different sorbents that are not equally effective under all conditions.
11 Considerable testing under many conditions is required to identify the most
12 effective sorbent at each location. Changes in fuel or combustion
13 characteristics can potentially make a previously effective sorbent
14 ineffective. Removal effectiveness and associated expense are dependent
15 on many factors including coal type, boiler design, operating conditions, and
16 existing air pollution control equipment configurations.
17

18 **Q. Will you please describe the concept of mercury emission reductions**
19 **possible from SO₂ controls?**

20 A. Mercury is present in the vapor phase of coal flue gases as a mixture of
21 oxidized and elemental mercury. Of these, oxidized mercury can be
22 absorbed efficiently by wet FGD systems, while elemental mercury typically
23 is not. For a wet FGD system to significantly remove mercury, the oxidized
24 fraction of the vapor phase mercury should be maximized. It has been

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1 found that the catalyst in some SCRs, the Company's primary NO_x emission
2 reduction technology, can be effective in oxidizing mercury. If an EGU has
3 an FGD in series with an SCR, mercury removal by the wet FGD will
4 typically be increased.

5

6 **Q. Were there any other emission reduction technologies evaluated by**
7 **Detroit Edison?**

8 A. Yes. Detroit Edison has and continues to evaluate alternative emission
9 control technologies with respect to its reduction strategy. Many of these
10 are in early stages of development and are unproven in full commercial
11 application. However, while under-developed alternatives continue to be
12 evaluated, Detroit Edison is utilizing proven technologies to meet the
13 requirements for emission reduction.

14

15 **Q. Will you please summarize Detroit Edison's emission compliance**
16 **strategy?**

17 A. As described above, the Company determined that the best emission
18 reduction strategy was to install a cost-effective combination of emission
19 reduction technologies on a number of units and hedge the economic and
20 compliance risk associated with participation in emission allowance
21 markets. The overall goal of the Company's plan is to achieve full
22 compliance in a safe and reliable manner for the least possible cost.

23

24 Unit by unit detail regarding the specific control technology chosen for each

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1 EGU is shown in Exhibit DE-16, Schedule F3-4, page 2. The years
2 indicated represent the "in-service" years for the respective unit and
3 technology.

4

5 **Q. How did Detroit Edison determine the optimal technology for specific**
6 **units?**

7 A. First, the Company compared the numerous technology options on each
8 unit to assess which ones would safely and reliably provide the necessary
9 NO_x, SO₂ and mercury emission reductions. Once this was done, the
10 remaining options were compared on a \$/ton (tons of NO_x and SO₂
11 emissions reduced) and a \$/pound (pounds of mercury emissions reduced)
12 basis. This included analysis of capital and operating costs (including any
13 production efficiency costs) and the expected emission reduction
14 efficiencies of the viable technologies.

15

16 Given their relative lower cost, certain combustion related technologies
17 (LNB, OFA, and CO) were chosen for NO_x reduction wherever practical,
18 given unit design and other constraints. These alone, however, do not
19 provide the required NO_x emission reductions to meet the NO_x SIP Call and
20 CAIR requirements. To achieve full compliance, additional controls are
21 needed.

22

23 As discussed above, SCR is the only technology that can achieve NO_x
24 reduction efficiency in excess of the 65% - 70% reduction requirement in the

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1 NO_x SIP Call and CAIR. In fact, given that SCR can reduce NO_x by 80% -
2 90%, EGUs that utilize SCR technology achieve some level of over-control.
3 In doing so, the Company was able to reduce expenditures otherwise
4 required on the remaining EGUs. It was determined that by installing SCR
5 technology at the Monroe Power Plant, the largest source of NO_x emissions
6 in the Detroit Edison system, the Company could minimize the overall cost
7 of the NO_x SIP Call and CAIR compliance by being able to utilize excess
8 reductions at other EGUs.

9

10 SO₂ emissions can be reduced on coal-fired EGUs by burning lower sulfur
11 fuels or by installing SO₂ reduction equipment. FGD, as described earlier,
12 can achieve greater than 95% reduction of SO₂ emissions, and were
13 selected for installation at the Monroe Power Plant for the same reasons as
14 SCR.

15

16 Significant uncertainty exists for both the cost and effectiveness of mercury
17 controls on EGUs. Detroit Edison has conducted extensive testing of both
18 mercury emissions and potential control technologies. To maximize the
19 benefits of mercury reductions achieved with NO_x and SO₂ control
20 technologies, SCR and FGD installations are scheduled to be installed on
21 the same units. Further mercury specific controls will be required to achieve
22 the expected required reductions for compliance. The company will install
23 sorbent injection equipment on several units to achieve the remaining
24 reductions.

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1

2 **Q. Why did Detroit Edison begin installing additional NO_x emission**
3 **reduction technology as early as 1999 and SO₂ reduction technology**
4 **in 2005?**

5 A. Construction of much of the control equipment takes a period of many
6 months to years. In addition, installation of emission reduction technologies
7 requires full unit outages and therefore must be timed such that the impact
8 to system reliability is minimized. Furthermore, completing the emission
9 reduction technology installations during normally scheduled periodic
10 outages reduces the overall fuel and purchase power costs associated with
11 the outage. Although much of the work can be completed while the unit is
12 online, full unit outages are required to complete final tie-ins. Since the
13 periodic outage frequency of most of Detroit Edison EGUs is 3-5 years,
14 emission reduction technology installations began prior to the time of
15 required compliance.

16

17 In addition, uncertainty regarding compliance timing and availability of
18 manpower and materials dictated that implementation of the compliance
19 plan commence well in advance of compliance deadlines.

20

21 **Q. How does Detroit Edison's emission reduction strategy compare with**
22 **that of similar utilities?**

23 A. The Company's compliance plan compares favorably to others in the NO_x
24 SIP Call and CAIR region in several ways. First, essentially all affected

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1 utilities are implementing technology based compliance strategies as
2 opposed to complete reliance on emission allowance markets.

3

4 Second, many companies appear to be utilizing similar technologies as well.
5 As each company evaluates their respective options, some differences
6 occur due to the specific nature of each company's generation asset
7 portfolio. However, given that SCR and FGD are the only technologies that
8 alone can achieve the NO_x SIP Call and CAIR requirements, they are critical
9 components of many compliance plans across the region. In fact, according
10 to EPA, approximately 61% of the coal-fired capacity in the region is
11 expected to utilize SCR and/or FGD technology by 2015. In addition, LNB,
12 OFA, and CO technologies are being utilized on almost all coal fired units in
13 the region.

14

15 **Q. What capital expenditures are required to implement the Company's**
16 **compliance strategy described above?**

17 A. The plan will require total capital expenditures of \$1.366 billion through
18 2011. Approximately \$664 million will be spent by the end of 2007. The
19 remainder will be spent in the 2008 – 2011 timeframe. Capital expenses (by
20 plant, by year) are listed in Exhibit DE-16, Schedule F3-4, page 1.

21

22 **Q. Will additional O&M expenditures be required to operate Detroit**
23 **Edison's NO_x, SO₂, and mercury reduction technologies?**

24 A. Yes. Mr. Harris discusses the expense associated with operating the

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1 emission control equipment in his direct testimony.

2

3 **Q. Given the costs associated with implementation of the emission**
4 **reduction compliance strategy and the performance of the**
5 **technologies placed in service to date, is Detroit Edison implementing**
6 **an effective and cost efficient strategy?**

7 A. Yes. The Company will not only meet the NO_x SIP Call, CAIR and CAMR
8 reduction requirements through implementation of the compliance strategy
9 identified in my testimony, but will do so in a cost effective manner.

10

11 With respect to the effectiveness of the strategy, the combustion
12 technologies already installed on numerous units and the SCR systems
13 installed at Monroe Power Plant are achieving the NO_x reductions expected.

14

15 Comparing the Company's plan of both installation of emission control
16 technologies and emission allowance market participation to current
17 emissions market forecast prices demonstrates that the Company's strategy
18 to install technology to the extent planned instead of complete reliance on
19 buying emission allowances from the market is economically justified. To
20 manage the risk of technology performance and emission market
21 uncertainty, it is appropriate to maintain some of the compliance strategy in
22 the emission market. If the long-term emission allowance market outlook
23 were to indicate falling emission allowance prices, the installation of
24 emission control technology could be slowed down or even deferred if

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1 allowance purchases became more economical than technology
2 installations. An accelerated plan to install and operate emission control
3 technologies could possibly become feasible if the long-term emission
4 allowance market outlook indicated increasing allowance prices or
5 decreasing availability that raised compliance concerns. The emission
6 market forecast will be continually monitored and re-evaluated in order to
7 speed or slow the timing of control technology installation to the extent
8 possible to maintain a cost effective strategy.

9

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

11 A. Yes, it does.

12