IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA Plaintiff, v. DTE ENERGY COMPANY, and DETROIT EDISON COMPANY Defendants.	))))))))))))	Civil Action No. 2:10-cv-13101-BAF-RSW Judge Bernard A. Friedman Magistrate Judge R. Steven Whalen

PLAINTIFF'S MOTION FOR PRELIMINARY INJUNCTION

Plaintiff United States of America, by its undersigned counsel, moves this Court for a preliminary injunction, pursuant to Fed. R. Civ. P. 65, requiring Defendants to take steps to offset the illegal pollution from Monroe Power Plant Unit 2. Defendants modified Monroe Unit 2 without obtaining permits and installing pollution controls as required by the Clean Air Act. This failure to comply with the law is causing irreparable harm to the public health downwind of the Monroe Plant. Plaintiff seeks a preliminary injunction requiring Defendants to (i) begin the process of obtaining the necessary permits for the Monroe Unit 2 modification and (ii) offset the pollution from Monroe Unit 2 through emissions reductions in Defendants' fleet of coal-fired power plants.

This motion is supported by the brief and exhibits filed herewith.

Respectfully submitted,

IGNACIA S. MORENO
Assistant Attorney General
Environment & Natural Resources Division

Dated: August 6, 2010 *<u>/s/ Thomas A. Benson</u>*

JUSTIN A. SAVAGE
Senior Counsel
THOMAS A. BENSON (MA Bar # 660308)
Trial Attorney
Environmental Enforcement Section
Environment & Natural Resources Division
U.S. Department of Justice
P.O. Box 7611
Washington, D.C. 20530
(202) 514-5261
thomas.benson@usdoj.gov

BARBARA McQUADE
United States Attorney
Eastern District of Michigan

ELLEN CHRISTENSEN
Assistant United States Attorney
Eastern District of Michigan
211 W. Fort St., Suite 2001
Detroit, MI 48226

OF COUNSEL:
SABRINA ARGENTIERI
MARK PALERMO
SUSAN PROUT
Associate Regional Counsel
United States Environmental
Protection Agency, Region 5
77 W. Jackson Blvd.
Chicago, IL 60604

APPLE CHAPMAN
Attorney Adviser
United States Environmental
Protection Agency
1200 Pennsylvania Ave. NW
Washington D.C. 20460

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Plaintiff,	)	Civil Action No. 2:10-cv-13101-BAF-RSW
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v.	)	Judge Bernard A. Friedman
	)	
DTE ENERGY COMPANY, and	)	Magistrate Judge R. Steven Whalen
DETROIT EDISON COMPANY	)	
	)	
	)	
Defendants.	)	
	)	

MEMORANDUM IN SUPPORT OF
PLAINTIFF'S MOTION FOR PRELIMINARY INJUNCTION

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ISSUES PRESENTED

Pursuant to Local Rule 7.1(d)(2), the issues presented by this motion are:

1. Whether a preliminary injunction is appropriate to minimize the harm from Defendants' violation of the New Source Review program of the Clean Air Act.

2. The nature of the preliminary injunction that best secures complete justice.

The leading authority supporting Plaintiff's argument is set forth on the next page.

LEADING AUTHORITY FOR THE RELIEF SOUGHT

I. Standard for Injunctive Relief

Cases
Winter v. NRDC, Inc., 129 S. Ct. 365 (2008)
Porter v. Warner Holding Co., 328 U.S. 395 (1946)
Stenberg v. Cheker Oil Co., 573 F.2d 921 (6th Cir. 1978)

II. Violation of Clean Air Act New Source Review Program

Cases
United States v. Ohio Edison Co., 276 F. Supp. 2d 829, 850 (S.D. Ohio 2003)
New York v. U.S. E.P.A., 413 F.3d 3 (D.C. Cir. 2005)

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42 U.S.C. § 7413
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III. Irreparable Harm and Appropriate Remedy

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INTRODUCTION

Defendants failed to comply with the law at Monroe Unit 2, and that failure is harming the health of the people living downwind of the plant: causing premature death, heart attacks, and respiratory problems, among other effects. Plaintiff United States comes before this Court seeking a preliminary injunction to minimize the harm to public health from Defendants' unpermitted pollution.

This is a case under the New Source Review ("NSR") program, one of the cornerstones of the modern Clean Air Act ("CAA" or "Act"). NSR is a tool to reduce pollution from individual sources. The program represents a compromise in the Clear Air Act Amendments passed in 1977: from that point on, new sources would have to obtain NSR permits and reduce harmful emissions by installing state-of-the-art pollution controls. However, existing sources would not have to make such emission reductions immediately. Instead, Congress deferred existing sources from NSR compliance until they were modified, a term defined in the statute as any physical change that results in an increase in pollution. As the D.C. Circuit Court explained shortly after the NSR law was passed: "The statutory scheme intends to 'grandfather' existing industries; but the provisions concerning modifications indicate that this is not to constitute a perpetual immunity from all standards under the . . . program. If these plants increase pollution, they will generally need a permit." *Alabama Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979).

Unit 2 at the Monroe Power Plant began operating in 1973, and has so far avoided the stringent emission reductions imposed by the NSR program. This spring, however, over the course of three months, Defendants DTE Energy Co. and Detroit Edison Co. (collectively "DTE" or "Defendants") performed a $65 million overhaul of Monroe Unit 2 that qualified as a

"modification" ending the unit's grandfathered status. By any measure, this was a large project – indeed, it was trumpeted on the front page of the local paper as "Extreme makeover: Power plant edition." As part of the overhaul, Defendants replaced and upgraded major components that had been breaking down and causing the unit to be unable to generate power. Replacing those worn out components will allow the unit to run more in the future – and to generate more pollution, thus triggering NSR. As the Seventh Circuit explained in a similar case, "aging produces more frequent breakdowns and so reduces a plant's hours of operation and hence its output," so renovating a plant to increase the plant's operating hours can trigger NSR. *United States v. Cinergy Corp.*, 458 F.3d 705, 709 (7th Cir. 2006). Here, the company's own projection forecast an emissions increase of 3,701 tons of sulfur dioxide ("SO_2") and 4,096 tons of oxides of nitrogen ("NO_x") per year – increases of 12% and 39%, respectively – both of which are far above the 40-ton level that requires an NSR permit. Defendants' own statements and projections thus show a huge, textbook modification that triggered pollution reduction requirements.

However, despite EPA's determination that the project required a permit and warning to Defendants not to operate the unit without following the law, DTE failed to obtain NSR permits or install pollution controls and began operating the unit again in June. The company thus avoided the NSR-mandated pollution reductions that were required of Unit 2 once it lost its grandfathered status. The state-of-the-art pollution controls required at modified sources can reduce emissions 90% to 99% at units like Monroe 2. Defendant's failure to install the required controls has resulted, and will continue to result, in massive amounts of unpermitted, uncontrolled pollution that would have been eliminated had the company complied with the law. This illegal pollution is causing harm to human health downwind of the Monroe power plant,

including premature mortality, heart attacks, and exacerbation of respiratory ailments like asthma.

Plaintiff United States comes before this Court seeking a preliminary injunction to minimize the harm from Monroe Unit 2's unpermitted pollution until a final judgment is reached and Defendants obtain the necessary NSR permits and begin operating state-of-the-art controls at Unit 2. Specifically, the United States respectfully requests that the Court order Defendants to (i) begin the process of obtaining the necessary NSR permits, and (ii) take steps to reduce emissions from Monroe Unit 2 or other coal-fired units in their system in order to mitigate and offset the excess pollution currently being emitted from Monroe Unit 2 as a result of Defendants' unpermitted modification of that unit.

BACKGROUND

I. THE CLEAN AIR ACT

Congress enacted the CAA "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." 42 U.S.C. § 7401(b)(1); *Nat'l Parks Conservation Ass'n, Inc. v. Tenn. Valley Auth.*, 480 F.3d 410, 412 (6th Cir. 2007) ("*NPCA*"); H. R. Rep. No. 91-1146, 91st Cong., 2d Sess. 1 (1970), *reprinted in* 1970 U.S.C.C.A.N. 5356 (purpose "is to speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the nation is wholesome once again."). Section 109 of the Act, 42 U.S.C. § 7409, requires EPA to establish national ambient air quality standards ("NAAQS") that specify the maximum permissible concentration of air pollutants in different areas of the country. The CAA requires states to meet these NAAQS by developing plans, called State Implementation Plans ("SIPs"), which impose regulatory requirements on individual sources of air pollution. 42

U.S.C. §§ 7410(a)(1), (a)(2). SIPs are subject to EPA approval; once approved they are federally enforceable. 42 U.S.C. §§ 7413(a), (b).

A. The New Source Review Program

The NSR program was added by the 1977 CAA Amendments after earlier programs failed to achieve the statutory goals. *See Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 567-68 (2007); *NPCA*, 480 F.3d at 412. Congress reaffirmed its dedication to using the Clean Air Act to reduce air pollution and improve public health: "First, and foremost, protection of the public health remains the paramount purpose and value under the Act. . . [T]he overriding commitment of the 1977 Act (just as the 1970 legislation) is to the protection of public health." Statement of Rep. Rogers, Clean Air Conference Report (1977): Statement of Intent; Clarification of Select Provisions, House Consideration of the Report of the Conference Committee, 123 CONG. REC. 27,070 (1977). In order to ease the initial burden of complying with NSR, Congress "grandfathered" existing sources from the program, so that they would only have to comply once they made modifications. The expectation was that, over time, the existing units would either be retired or would undergo overhauls to keep operating, and that those overhauls would trigger NSR. "Congress chose to 'grandfather' existing pollution sources from the NSPS and NSR provisions at the time the statute was enacted. . . Congress did not, however, intend that such existing sources be forever spared the burden and expense of installing pollution control devices." *United States v. Ohio Edison Co.,* 276 F. Supp. 2d 829, 850 (S.D. Ohio 2003); *see also Alabama Power*, 636 F. 2d at 400; *United States v. Cinergy Corp.*, 458 F.3d 705, 709 (7th Cir. 2006) ("The Clean Air Act treats old plants more leniently than new ones . . . But there is an expectation that old plants will wear out and be replaced by new ones that will be subject to the more stringent pollution controls that the Clean Air Act imposes on new plants.").

The NSR program has two components: a Prevention of Significant Deterioration ("PSD") program applying in areas of the country that do not exceed the NAAQS, 42 U.S.C. §§ 7470-7479, and a Nonattainment NSR ("NNSR") program for areas that fail to satisfy the NAAQS, 42 U.S.C. §§ 7501-7515. *See Duke Energy*, 549 U.S. at 567-68. The statutory purposes of the PSD program include:

- protecting "public health and welfare from any actual or potential adverse effect which in the [EPA] Administrator's judgment may reasonably be anticipate[d] to occur from air pollution" and
- ensuring that "emissions from any source in any State will not interfere with any portion of the applicable [SIP] to prevent significant deterioration of air quality for any other State."

42 U.S.C. § 7470(1), (4).[1]

Both the PSD and NNSR programs are relevant here because the Monroe Power Plant is located in Monroe County, Michigan, a region in attainment with SO_2 and NO_X standards but that has failed to reach the PM2.5 NAAQS. PM2.5 consists of particles that are 2.5 microns or less, where 1 micron is 1 millionth of a meter. Ex. 1, Declaration of Lyle Chinkin ("Chinkin Dec.") ¶8. As described in Section II.B of the Argument, these particles can lodge deep in the lung and cause myriad health problems.

While some of the details and terminology differ, for the purposes of this motion, PSD and NNSR can be treated together. Both require a source to obtain permits and install state-of-the-art pollution controls, required by statute to be the "best available control technology," whenever the source undergoes a major modification. 42 U.S.C. §§ 7475(a) (PSD), 7503

[1] The other listed statutory purposes are to protect and enhance air quality in national parks and other special areas; ensure that economic growth will "occur in a manner consistent with the preservation of existing clean air resources;" and to ensure careful review and public participation. 42 U.S.C. § 7470.

(NNSR). A major modification is any physical change that would be expected to result in a significant net increase in emissions. Mich. Admin. Code R. 336.2801(aa)(i) (PSD rules); 40 C.F.R. § 51 Appendix S (NNSR rules).[2] For both SO_2 and NO_X, any emissions increase greater than 40 tons per year triggers NSR. Mich. Admin. Code R. 336.2801(qq). Increases in SO_2 trigger PM2.5 NSR review because SO_2 is a so-called "precursor," *i.e.*, SO_2 converts to PM2.5 once in the air. 73 Fed. Reg. 28,321, 28,325-28 (May 16, 2008). Thus a physical change that increases SO_2 can trigger NSR review for both SO2 *and* PM2.5.

The applicable rules require that NSR applicability be determined *before* a source begins work. *Ohio Edison*, 276 F. Supp. 2d at 881; *United States v. S. Ind. Gas & Elec. Co.,* No. IP99-1692-C-M/F, 2002 WL 1629817, at *3 (S.D. Ind. July 18, 2002). If a project constitutes a modification, sources are required to obtain a permit, install pollution controls, and meet other requirements before beginning the work. *See, e.g.*, 42 U.S.C. §§ 7475(a), 7503(a). Obtaining a permit, designing, and installing the necessary controls can take up to three to four years. Ex. 3, Declaration of Ranajit Sahu ("Sahu Dec.") ¶20.

B. Regulatory Exemptions From New Source Review

There are two regulatory exemptions to NSR that Defendants invoke here: one for routine maintenance projects and one for emissions increases that are unrelated to the physical change. *See* Ex. 2-C, March 12, 2010 Letter from Kelly Guertin (DTE Energy) to William Presson (Michigan Department of Environmental Quality) ("Notice Letter"). At the outset of the NSR program, EPA created an exception for physical changes that constitute routine maintenance, repair, or replacement. EPA must interpret the "routine maintenance" exception narrowly "as limited to '*de minimis* circumstances.'" *New York v. EPA* ("*New York II*"), 443 F.3d 880, 884

[2] EPA has approved Michigan's SIP with respect to the PSD rules, but not with respect to the relevant NNSR rules. Thus the Michigan SIP sets forth the federally enforceable PSD rules, while EPA regulations control for NNSR. In practice, the standards are essentially the same for the purposes of the Monroe Unit 2 project.

(D.C. Cir. 2006); *see also Alabama Power*, 636 F.2d at 400. The statute compels a narrow reading of the exemption; the CAA contains no exception to the PSD provisions. Nonetheless the D.C. Circuit has held that, because "the law does not concern itself with trifling matters," the EPA has the discretion to exempt "some emission increases on the grounds of *de minimis* or administrative necessity." *Alabama Power*, 636 F.2d at 360, 400. That discretion, however, "is narrow in reach and tightly bounded by the need to show that the situation is genuinely *de minimis* or one of administrative necessity." *Id.* at 361; *see also New York II*, 443 F.3d at 884, 888.

EPA made the limited nature of the exemption clear to Defendants a decade ago after DTE asked for an applicability determination for an upgrade project at other coal-fired electric generating units at the Monroe Plant. EPA issued a determination that the project did not qualify as routine, but that it would not trigger NSR if there was no emissions increase (as Detroit Edison claimed in its request). Ex. 4, May 23, 2000 Letter from Frank Lyons (U.S. EPA) to Henry Nickel (Hunton & Williams) ("Applicability Determination"). In its analysis, EPA noted that the definition of modification in the statute and regulations is "sweeping" in scope and that "any regulatory exemption . . . should be interpreted in a limited way." *Id.* at 13. EPA stressed the "narrowly limited scope of the exemption" and stated that routine should be given its typical meaning: "of a commonplace or repetitious character . . . relating to . . . established procedure." *Id*. at 15.

The other exemption Defendants have raised allows a source to exclude emissions increases not related to the physical change and is known as the "demand growth" or "capable of accommodating" exclusion. The standard for excluding any portion of an emissions increase requires the utility to show that "(1) [t]he unit could have achieved the necessary level of

utilization during the consecutive 24-month period [the source] selected to establish the baseline actual emissions; and (2) the increase is not related to the physical or operational change(s) made to the unit." *New York v. U.S. E.P.A.*, 413 F.3d 3, 33 (D.C. Cir. 2005) (citing 67 Fed Reg. 80,186, 80,203 (Dec. 31, 2002)); *see also* Mich. Admin. Code R. 336.2801(b)(ii)(C).

C. Clean Air Act Enforcement Provisions

The Clean Air Act includes two enforcement provisions relevant to this case. The first is Section 113 of the Act, 42 U.S.C. § 7413, which grants EPA the authority to take action against violations of the CAA or approved state SIPs. Under Section 113(b), EPA can seek injunctive relief and civil penalties of up to $37,500 per day for each such violation after January 12, 2009, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701. The second enforcement provision is specific to PSD violations. Section 167 of the Act provides that: "The [EPA] Administrator shall . . . take such measures, including issuance of an order, or seeking injunctive relief, as necessary to prevent the construction or modification of a major emitting facility which does not conform to the requirements of [PSD] . . . ." 42 U.S.C. § 7477.

II. DEFENDANTS AND THE MONROE POWER PLANT

Defendant DTE Energy Co. is a publicly traded utility holding company headquartered in Detroit, Michigan. Defendant Detroit Edison Co. is a wholly-owned subsidiary of DTE Energy Co. Both are Michigan corporations with the same principal place of business in Detroit, Michigan. Detroit Edison owns and operates the Monroe Power Plant, while DTE Energy qualifies as an operator of the plant under the Clean Air Act based on its involvement in decisions concerning capital projects, like those at issue in this case, and environmental permitting.

Defendants own and operate six coal-fired plants in Michigan. Ex. 2, Declaration of Ethan Chatfield ("Chatfield Dec.") ¶6. The Monroe plant is located in Monroe, Michigan, on the western shore of Lake Erie and approximately 40 miles southwest of Detroit. Ex. 1, Chinkin Dec. ¶20 & Figure 15 (map of DTE plants). The plant has four coal-fired electric generating units called Units 1-4. Monroe Unit 2 is an 823 megawatt ("MW") unit that began operation in 1973. At the time Monroe Unit 2 was constructed, the industry expected that units would operate for 30 to 35 years before being retired or relegated to occasional service. Ex. 5, Declaration of Robert Koppe ("Koppe Dec.") ¶33. Monroe Unit 2 has already operated beyond its original life expectancy. *Id.*

A power plant consists of three major elements: the boiler, the turbine, and the generator. Ex. 6, Declaration of A. Michael Hekking ("Hekking Dec.") ¶6. The boiler is a large structure (12 stories tall for Monroe 2) where coal is burned and the energy from the burning coal is transferred to water to create the steam that turns the turbine. Ex. 6, Hekking Dec. ¶¶6-7; Ex. 2-D, April 22, 2010 Article by Charles Slat from "The Monroe Evening News" entitled, "Extreme makeover: Power plant edition" ("Extreme Makeover Article"). The boiler is largely comprised of components of tubes that carry water and steam. Ex. 6, Hekking Dec. ¶6. The economizer, pendant reheater, and waterwalls at issue in this case are each major boiler components. Ex. 5, Koppe Dec. ¶73.[3]

Monroe Unit 2 has no advanced SO_2 or NO_X pollution controls, while the remaining Monroe units already have state-of-the-art pollution controls for SO_2 and NO_X installed or under construction. DTE has stated that it will install flue gas desulfurization ("FGD"), the most effective SO_2 pollution control, at Unit 2 by approximately 2014. Ex. 2-B, December 8, 2009 DTE Energy Press Release entitled, "DTE Energy Environmental Project Will Create 900 Jobs."

[3] For a more detailed description of the way a coal-fired utility boiler works, see Ex. 6, Hekking Dec. ¶¶6-15.

DTE also publicly announced that it would install selective catalytic reduction ("SCR"), the top NO_X control, but now says it said it has no firm plans to do so. Ex. 2, Chatfield Dec. ¶17; Ex. 2-B.

Monroe Unit 2 emitted 27,230 tons of SO_2 and 8,205 tons of NO_X in 2009, and was the largest individual emitting unit of both pollutants in the state of Michigan that year. Ex. 1, Chinkin Dec. ¶5. Among other effects, the SO_2 and NO_X emissions from the plant contribute to the formation of tiny particles known as PM2.5, while the NO_X emissions from the plant contribute to ground-level ozone. *Id.* ¶¶8, 10. EPA has determined that, "Both ozone and $PM_{2.5}$ are associated with serious public health problems, including premature mortality . . . ." 75 Fed. Reg. 22,896, 22,900 (Apr. 30, 2010).

III. EPA ENFORCEMENT HISTORY AND THE MONROE UNIT 2 PROJECT

A. The Monroe Unit 2 Overhaul

On or about March 13, 2010, DTE began a $65-million overhaul at Monroe Unit 2. Ex. 2-D, Extreme Makeover Article. This project included the complete replacement of two major boiler components: the pendant reheater (also known as the high temperature reheater) and the economizer, at a cost of approximately $30 million. *Id.* Defendants also replaced about 2,000 square feet of waterwall tubes from the boiler. Ex. 5, Koppe Dec. ¶54. For each of the major boiler components replaced, DTE staff described the problem posed by the component and the objective of the replacement in documents justifying the capital spending:

- *Economizer*: "The Unit 2 economizer tubes have been damaged during lengthy service in an erosive environment. Tube failures and forced outages are occurring at an increasing rate. Objective: Operation of the unit without forced outages caused by economizer tube failures.

- *High Temperature Reheater*: "Unit 2 has experienced reheater pendant failures resulting in forced outages. Analysis done by the Boiler Tube Task Force predicts more frequent failures in the future. Objective would be to improve the reliability of Unit 2."
- *Waterwalls*: "improve reliability due to water wall tube failure."

Ex. 2-F, Excerpts of DTE Documents Produced in Response to Request During EPA's June 2, 2010 Inspection of Monroe Generating Station ("Inspection Documents"). At peak, the project required 700 contract workers at the site. Ex. 2-A, June 3, 2010 Notes from M. Ackerman and E. Chatfield (U.S. EPA) of June 2, 2010 Monroe Generating Station Inspection ("Inspection Notes") at 2. Removing the old boiler components required cutting "a giant access hole near the top of the 12-story power plant." Ex. 2-D, Extreme Makeover Article. The new components are so heavy that they must be hoisted in pieces by a "giant crane" and then loaded onto a monorail built specifically for the project that carries them to the point of installation. *Id.* The project was unprecedented in the four decade history of the Monroe Power Plant. *Id.*; Ex. 2-A, Inspection Notes at 2-4. On April 22, 2010, about halfway through the project, the work was described in the lead story on the front page of the local newspaper as "Extreme makeover: Power plant edition." Ex. 2-D, Extreme Makeover Article.

DTE mailed a notification letter ("Notice Letter") to the Michigan Department of Natural Resources and Environment on March 12, 2010 – the day before starting the project. Ex. 2-C, Notice Letter. Under the applicable rules, DTE is required to provide notice and retain information about capital projects that *could* trigger NSR, even if the company believes the projects do not trigger. Mich. Admin. Code R. 336.2818(3). The Notice Letter stated that DTE was about to begin a 12-week outage. In the Notice Letter, DTE projected huge emissions

increases after the project, but stated that the company believed it did not need to proceed with NSR permitting because certain regulatory exclusions applied. DTE began the project the very next day, completing construction activities and resuming operation of Monroe Unit 2 in June.

B. EPA Enforcement History

EPA had been investigating potential NSR violations at Monroe and the other DTE plants well before Defendants began the 2010 Monroe Unit 2 project. In July 2009, EPA issued a Notice of Violation ("2009 NOV") to DTE, which cited 35 prior construction projects at the Monroe plant and other DTE coal-fired power plants – each of which the NOV stated were "major modifications" that increased emissions – as NSR violations. Ex. 2, Chatfield Dec. ¶24. EPA and DTE met to discuss those violations in September 2009 at a formal NOV "conference," an opportunity that EPA generally provides companies receiving an NOV under the Act. There, EPA informed the company that it disagreed with DTE's application of the NSR rules and its conclusions that numerous prior projects did not trigger NSR. *Id.* ¶¶24-26. At the conference, EPA also invited DTE to discuss the matter further if it had any uncertainty about EPA's position on when construction projects required NSR preconstruction permits. *Id.* ¶26. Six months later, DTE went ahead with the Monroe Unit 2 project. This $65 million construction project was larger in cost and scope than any of the projects in EPA's July 2009 NOV. In excusing itself from NSR permitting, DTE relied on the same analysis that EPA specifically told DTE was insufficient to exempt prior construction projects from permitting.

Despite the 2009 NOV, and EPA's warnings at the conference, DTE did not contact EPA about the Monroe Unit 2 project. Instead, EPA received a copy of the Notice Letter on May 21, 2010, two months into construction. Because the letter itself demonstrated NSR liability unless Defendants' asserted defenses were viable, EPA issued Defendants several requests for

information pursuant to its authority under Section 114 of the Clean Air Act, 42 U.S.C. § 7414. Ex. 2, Chatfield Dec. ¶12 n.3. Defendants' responses confirmed that the company expected an emissions increase and that no defenses to NSR applicability existed. On June 4, 2010, EPA issued Defendants an NOV specifically for the Monroe Unit 2 project, finding that it violated PSD and NNSR. Ex. 2-E. On the same day, EPA provided a final warning: the Agency sent a letter to Defendants stating that the project violated NSR and that, "The seriousness of the violation would be compounded by beginning operation of the illegally modified unit." Ex. 2-J, June 4, 2010 Letter from Phillip Brooks (U.S. EPA) to Michael Solo (DTE Energy). Defendants restarted the unit, and the instant complaint followed.

The United States' complaint may be amended to allege additional claims, but we filed now because of the uniquely flagrant nature of the NSR violation and the importance of obtaining preliminary relief.

ARGUMENT

Defendants performed a $65-million overhaul of the aged Monroe Unit 2 without complying with NSR. The failure to follow the law means the unit will emit much more pollution than it otherwise would have if Defendants had obtained NSR permits and installed pollution controls. The likelihood of success on the merits and the stark public health harm from Defendants' unpermitted emissions support a preliminary injunction that will minimize the harm by requiring pollution reductions to make up for Monroe Unit 2's unpermitted emissions.

I. THE COURT'S EQUITABLE AUTHORITY

A. Legal Standard For Issuing A Preliminary Injunction

The traditional standard for an injunction requires the plaintiff to show "that he is likely to succeed on the merits, that he is likely to suffer irreparable harm in the absence of preliminary relief, that the balance of equities tips in his favor, and that an injunction is in the public interest." *Winter v. NRDC, Inc.*, 129 S. Ct. 365, 374 (2008). Traditionally, Sixth Circuit courts have balanced the four factors set out above in evaluating a motion for preliminary injunction. *Overstreet v. Lexington-Fayette Urban County Government,* 305 F.3d 566, 573 (6th Cir. 2002) ("These factors are not prerequisites, but are factors that are to be balanced against each other."). "Although the factors are to be balanced, a finding that there is no likelihood of irreparable harm or no likelihood for success on the merits is usually fatal." *Livonia Prop. Holdings, L.L.C. v. 12840-12976 Farmington Rd. Holdings, L.L.C.*, No. 10-11589, -- F. Supp. 2d --, 2010 WL 1956867, at *4 (E.D. Mich. May 13, 2010) (citing *Winter*, 129 S. Ct. at 374 and *Gonzales v. Nat'l Bd. of Med. Exam'rs*, 225 F.3d 620, 625 (6th Cir. 2000)).

B. The Court Has Broad Equitable Authority

Once the Court decides equitable relief is appropriate, it has broad discretion to craft the most appropriate relief to "secur[e] complete justice." *United States v. Universal Mgmt. Servs., Inc., Corp.*, 191 F.3d 750, 762 (6th Cir. 1999).

The Court's equitable authority in this case does not come just from the Clean Air Act, but is inherent in the Court's equitable jurisdiction itself. "For several hundred years, courts of equity have enjoyed sound discretion to consider the necessities of the public interest when fashioning injunctive relief." *United States v. Oakland Cannabis Buyers' Co-op.*, 532 U.S. 483, 496 (2001) (internal citations and quotation marks omitted). This tradition can be traced

throughout American history back to English common law. *Franklin v. Gwinnett County Pub. Schools*, 503 U.S. 60, 66-67 (1992). Unless specifically curtailed by Congress, "all the inherent equitable powers of the District Court are available for the proper and complete exercise of [its equitable] jurisdiction." *Porter v. Warner Holding Co.*, 328 U.S. 395, 398 (1946); *Universal Mgmt. Servs.*, 191 F.3d at 761. Indeed, "the court may go beyond the matters immediately underlying its equitable jurisdiction and decide whatever other issues and give whatever other relief may be necessary under the circumstances. Only in that way can equity *do complete rather than truncated justice*." *Porter*, 328 U.S. at 398 (emphasis added).

The traditional equitable authority entrusted to the district court includes the power to enjoin otherwise lawful conduct as necessary to mitigate past harm from violations of law. In another NSR enforcement case, the *Cinergy* court found that "it has the authority to order Defendants to take appropriate actions that remedy, mitigate and offset harms to the public and the environment caused by the Defendants' proven violations of the CAA." *United States v. Cinergy Corp.*, 582 F. Supp. 2d 1055, 1060 (S.D. Ind. 2008); *see also Garrison v. Baker Hughes Oilfield Operations, Inc.*, 287 F.3d 955, 961 (10th Cir. 2002) ("'A federal court's equity jurisdiction affords it the power to enjoin otherwise lawful activity when necessary and appropriate in the public interest to correct or dissipate the evil effects of past unlawful conduct.'") (quoting *United States v. Holtzman*, 762 F.2d 720, 724-25 (9th Cir. 1985)) (further citations omitted); *United States v. Deaton*, 332 F.3d 698, 713-14 (4th Cir. 2003) (Clean Water Act case). By allowing courts to "grant additional injunctive relief . . . remedying harm caused by [defendants'] past violations," equity "gives meaning to the statute's grant of enforcement authority." *U.S. Public Interest Research Group v. Atlantic Salmon of Maine, LLC*, 339 F.3d 23, 31 (1st Cir. 2003) (Clean Water Act case).

A district court's equitable authority is at its apex when the public interest is at stake. In such cases, a district court's "equitable powers assume an even broader and more flexible character than when only a private controversy is at stake." *Porter*, 328 U.S. at 398 (citing *Virginian Ry. Co. v. Sys. Fed'n No. 40*, 300 U.S. 515, 552 (1937)); *United States v. Miami Univ.*, 294 F.3d 797, 819 (6th Cir. 2002) ("Courts of equity may, and frequently do, go much farther both to give and withhold relief in furtherance of the public interest than they are accustomed to go when only private interests are involved.") (quoting *Virginian Railway*, 300 U.S. at 552). Statutes like the Clean Air Act that are devoted to, among other goals, protecting public health provide a compelling justification for expansive injunctive relief. As one court explained in a case under the Safe Drinking Water Act, "[T]he Court has the responsibility in this case of crafting a remedy that is protective of public health, *and this responsibility necessarily takes preeminence over all other considerations*." *United States v. Alisal Water Corp.*, 326 F. Supp. 2d 1010, 1027 (N.D. Cal. 2002) (emphasis added).

Contrary to what Defendants may argue, the Court is not limited to prohibitory injunctions or maintaining the status quo in a preliminary injunction, nor is there a heightened standard for injunctions that go beyond maintaining the status quo. The Sixth Circuit has made clear that "the focus always must be on prevention of injury by a proper order, not merely on preservation of the status quo." *Stenberg v. Cheker Oil Co.*, 573 F.2d 921, 925 (6th Cir. 1978). In a more recent case the Sixth Circuit further explained,

> We therefore see little consequential importance to the concept of the status quo, and conclude that the distinction between mandatory and prohibitory injunctive relief is not meaningful. . . [We] hold that the traditional preliminary injunctive standard -- the balancing of equities -- applies to motions for mandatory preliminary injunctive relief as well as motions for prohibitory preliminary injunctive relief.

United Food & Commercial Workers Union, Local 1099 v. Southwest Ohio Reg'l Transit Auth., 163 F.3d 341, 348 (6th Cir. 1998).

II. THE PUBLIC IS ENTITLED TO PRELIMINARY INJUNCTIVE RELIEF

The traditional injunctive relief factors strongly favor the United States' proposed relief. The United States is highly likely to succeed on the merits. This is a $65-million overhaul that Defendants themselves predict will cause a massive emissions increase. It was done in open defiance of EPA, the federal agency Congress charged with enforcing the law. *See Ala. Dep't of Envtl. Conservation v. EPA*, 540 U.S. 461, 464 (2004) ("Congress vested EPA with explicit and sweeping authority to enforce CAA 'requirements' relating to the construction and modification of sources under the PSD program"). The irreparable harm is stark: Defendants' unpermitted pollution is causing harm – including premature death – to the public. That injury, which goes to both the irreparable harm and public interest factors, could be largely eliminated by the relief sought by the United States. Finally, the burden on Defendants is minimal by comparison. DTE will still be able to operate the unit, but will simply have to reduce emissions. The cost of the interim pollution reduction is small enough not to impact Defendants or their customers.

A. The United States Is Likely To Succeed On The Merits

To establish a violation of NSR, the plaintiff must show that: (a) a defendant is a "person" who "owns" or "operates" the source;[4] (b) the source is a "major emitting facility;" (c) the defendant "modified" the source through a "physical change" that would result in a

[4] Detroit Edison holds itself out as the owner and operator of the Monroe plant. Defendants may argue that DTE Energy does not qualify as either an owner or an operator. Under the case law, an entity qualifies as an operator if it "had 'significant or substantial or real control and supervision' over a project." *United States v. Anthony Dell'Aquilla, Enter. & Subsidiaries.,* 150 F.3d 329, 334 (3rd Cir. 1998) (quoting *United States v. Walsh*, 783 F. Supp. 546, 548 (D. Wash. 1991)). DTE has such control: for instance, the DTE Energy CEO and chairman of the board had to approve the component replacements that triggered NSR liability. Ex. 2-F, Inspection Documents. The Notice Letter also references DTE as the entity performing the project. Ex. 2-C, Notice Letter. In any event, the Court need not address DTE Energy's liability at this stage, since there is no dispute about Detroit Edison's status as a liable party.

"significant net increase in emissions" of any air pollutant subject to regulation under the Act; and (d) the defendant failed to obtain an NSR permit and failed to apply the requisite pollution controls. 42 U.S.C. §§ 7413(b), 7475(a), 7479(2)(C). The only element that requires analysis is whether the project constitutes a major modification under NSR; the other elements are uncontroversial. Ex. 2, Chatfield Dec. ¶¶7, 9, 17 (addressing elements (a), (b), and (d) above). In addition, Defendants' own submissions make clear that there was both a physical change[5] and a projected increase in emissions. Thus Defendants' liability hinges on the applicability of two regulatory exemptions to NSR applicability. As discussed in turn below, neither the exemption for routine maintenance nor that for emissions increases unrelated to the project avails DTE here.

1. The Project Is Not Routine Maintenance

Defendants spent $65 million in an unprecedented effort to improve the performance of Monroe Unit 2. We discuss below the details of the routine maintenance analysis, but common sense compels the conclusion that this project was "anything but routine." *See United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 861 (S.D. Ohio). As the *Ohio Edison* court explained

> While the analysis required to distinguish between a modification sufficient to trigger compliance from routine maintenance, repair and replacement is complex, the distinction is hardly subtle. Routine maintenance, repair and replacement occurs regularly, involves no permanent improvements, is typically limited in expense, is usually performed in large plants by in-house employees, and is treated for accounting purposes as an expense. In contrast to routine maintenance stand capital improvements which generally involve more expense, are large in scope, often involve outside contractors, involve an increase of value to the unit, are usually not undertaken with regular frequency, and are treated for accounting purposes as capital expenditures on the balance sheet.

276 F. Supp. 2d at 834.

In determining whether a project qualifies for the routine maintenance exemption, EPA has typically considered four factors known as the "WEPCO factors": (1) nature and extent; (2)

[5] Under the law, physical change is defined extremely broadly, so there is no question that a physical change has occurred here. *See, e.g.*, *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 905 (7th Cir. 1990).

purpose; (3) frequency; and (4) cost. *See, e.g.*, *Ohio Edison*, 276 F. Supp. 2d at 834. As described in Section I.B of the Background, the exemption is narrowly construed. The burden of demonstrating that the exemption applies rests with DTE. *See, e.g.*, *id.* at 856 (citing *United States v. First City Nat'l Bank of Houston*, 386 U.S. 361, 366 (1967)); *N.L.R.B. v. Kentucky River Cmty. Care, Inc.*, 532 U.S. 706, 711 (2001) (applying "general rule of statutory construction that the burden of proving justification or exemption under a special exception to the prohibitions of a statute generally rests on one who claims its benefits.") (internal citations omitted). Each of these factors supports a finding that this project is far from routine.

Nature and extent. This project was extremely large by any measure. Plaintiff's expert witness Michael Hekking, a former plant manager with the Tennessee Valley Authority, describes the nature and extent as "massive." Ex. 6, Hekking Dec. ¶45. The project leader DTE hired to manage the project agreed, calling it a "large, labor-intensive job." Ex. 2-D, Extreme Makeover Article. Both the economizer and pendant reheater replacements were considered major capital projects by DTE, and required the approval of senior company officials, including the CEO and Chairman of the Board of DTE Energy. Ex. 2-H, Direct Testimony of Paul Fessler before Michigan Public Service Commission, Case No. U-15768 ("Fessler Testimony"); Ex. 2-F, Inspection Documents.

Purpose. After nearly 40 years of operation, the pendant reheater and economizer had reached the end of their useful life. Ex. 5, Koppe Dec. ¶116. The purpose of the project was to replace those components with upgraded designs and materials in order to avoid forced outages and thus improve the ability of the plant to generate electricity. Ex. 2-F, Inspection Documents. Such purposes have been treated in the past by courts and by EPA as a clear indication that a project is not routine, especially given that increased availability from fewer forced outages also

often effectively results in a life extension of the unit in question. *See Ohio Edison*, 276 F. Supp. at 860; Ex. 7, September 9, 1988 Memo from Don Clay (U.S. EPA) to David Kee (U.S. EPA) ("Clay Memo") at 3-4.

Frequency. This project is unique in the four-decade history of the Monroe Power Plant. First, it is the first time DTE has completely replaced the economizer or pendant reheater at Monroe Unit 2. Ex. 2-A, Inspection Notes at 2-3. Second, it is the first time that DTE has performed work on *both* the economizer and the reheater at the same time. Ex. 2-D, Extreme Makeover Article. The unprecedented nature of the work makes it clear that this project is highly infrequent. *See* Ex. 7, Clay Memo at 5 (project is infrequent when it occurs once or twice during the life of the unit); Ex. 4, Applicability Determination at 3 (same).

Cost. The total cost of the March to June 2010 outage work at Monroe Unit 2 was approximately $65 million, of which approximately $30 million was spent on replacing the pendant reheater and the economizer. The reheater and economizer replacements were capital improvement projects. Ex. 2-H, Fessler Testimony. Such large capital expenditures are not routine. Ex. 7, Clay Memo at 3 (projects that require significant expenditures of capital, rather than maintenance funds, are not routine).

If a $65-million unit overhaul qualifies as routine maintenance, the exemption has "swallow[ed] both the rule and specific provisions of the Clean Air Act." *Ohio Edison*, 276 F. Supp. 2d at 855. This project is far from routine.

2. The Project Will Cause a Significant Net Emissions Increase

Defendants have conceded that at the time of the project they expected massive emissions increases: NSR is triggered with an increase of 40 tons per year of NO_X or SO_2, and Defendants predicted emissions increases about 100 times larger.[6] The only question is whether Defendants can show that the increase is unrelated to the project and qualify for the "capable of accommodating" exclusion. As we discuss below, DTE cannot make the necessary showing. There are two independent bases for finding an emissions increase. First, because DTE cannot satisfy the requirement to exclude its projected emissions increase as unrelated to the project, its own Notice Letter demonstrates an NSR-triggering increase. Second, Plaintiff's witnesses have looked at DTE's documents and determined that the company should expect emissions to increase as a result of the overhaul.

Emissions Increase Based On DTE's Notice Letter

Defendants admit that they expected a huge emissions increase after the project. In its Notice Letter, DTE presented emissions calculations showing an increase of 3,701 tons of SO_2 and 4,096 tons of NO_x per year, each an order of magnitude larger than the NSR significance threshold. Ex. 2-C, Notice Letter. This projected increase was based on the results of a production cost model known as PROMOD, a model used by DTE and other utilities to forecast how their units will be utilized in the future and therefore what resources will be required (for instance, the amount of coal to purchase). *Id.* The PROMOD analysis DTE used was the same analysis that formed the basis of DTE's application to the Michigan Public Service Commission for recovering power supply costs from ratepayers. *Id.*; Ex. 8, Declaration of Bruce Biewald

[6] In determining whether an emissions increase exists, the applicable rules require comparing annual emissions over a 24-month period in the five years before the project with expected annual emissions after the project. Defendants selected separate 24-month periods as their NO_X and SO_2 baselines, and we have used those baselines in our analysis.

("Biewald Dec.") ¶¶8-10. The Notice Letter and the supporting PROMOD analysis demonstrate that – at the time it began the project – DTE actually expected a huge emissions increase. Ex. 2-C, Notice Letter; Ex. 8, Biewald Dec. ¶7. Unless DTE can show that a defense applies, that expectation is sufficient to trigger NSR obligations. *Ohio Edison,* 276 F. Supp. 2d at 850 ("compliance with the CAA is triggered when an existing source makes a 'modification' which results in an increase in emissions, unless a regulatory exemption applies to the activity."); Ex. 3, Sahu Dec. ¶14.

DTE asserted in the Notice Letter that its *entire* projected emissions increase could be excluded under a regulatory exemption for emissions increases not related to the project known as the demand growth or capable of accommodating exclusion. The standard for excluding any portion of an emissions increase requires the utility to show that "(1) [t]he unit could have achieved the necessary level of utilization during the consecutive 24-month period [the source] selected to establish the baseline actual emissions; and (2) the increase is not related to the physical or operational change(s) made to the unit." *New York v. U.S. E.P.A.*, 413 F.3d 3, 33 (D.C. Cir. 2005) (citing 67 Fed Reg. 80,186, 80,203 (Dec. 31, 2002)); *see also* Mich. Admin. Code R. 336.2801(b)(ii)(C). The burden for demonstrating that emissions can be excluded rests with the source. *See* Ex. 9, *United States v. Cinergy Corp*., 1:99-cv-01693-LJM-JMS (S.D. Ind.), Final Jury Instructions, Dkt. 1535, May 21, 2008 ("The burden is on Defendants to prove by a preponderance of the evidence that the demand growth exclusion applies to an emissions increase."); *Kentucky River Cmty. Care*, 532 U.S. at 711 (applying general rule that party claiming benefit of exemption bears burden).

First, the company has failed to meet its pre-project obligations for asserting the capable of accommodating exclusion. Under the NSR rules, DTE has an obligation to maintain records

to substantiate any claimed exclusion. 72 Fed. Reg. 72,607, 72,610 (Dec. 21, 2007); Mich. Admin. Code R. 336.2818(3)(a)(f), (4). In a May 28, 2010 Information Request to DTE under its Section 114 authority, EPA sought any information DTE believes supports its contention that the work done during the outage does not require a permit. Ex. 2-I, May 28, 2010 Letter from Phillip Brooks (U.S. EPA) to Michael Solo (DTE Energy). DTE failed to provide any information to substantiate its exclusion claim. Since NSR requires a pre-project applicability determination, the failure to develop and maintain information to support its exclusion precludes DTE from relying on it as a defense now.

Second, DTE's own documents demonstrate that it expected emissions to increase *as a result of* the project. As described above, the company's project justification documents stated that replacing the economizer and pendant reheater was necessary to eliminate forced outages and improve unit availability. This is reflected in the company's expectations and planning modeling. For the baseline periods before the project, DTE reported that Monroe Unit 2 was forced out of service from 14% to 17% of the time. Ex. 5, Koppe Dec. ¶89. In the PROMOD modeling run that formed the basis for DTE's submissions to the state, the company assumed that the outage rate would drop to 8% to 9% after the project. Ex. 2-G, June 3, 2010 Letter from Michael Solo (DTE Energy) to Mark Palermo (U.S. EPA) ("DTE June 3, 2010 Letter"). The only change at the unit that could explain such a significant performance improvement is the project. Ex. 5, Koppe Dec. ¶¶89, 119-123. Defendants' own PROMOD modeling also shows that after the project, Monroe Unit 2's availability and generation are expected to increase. Ex. 2-G, June 3 DTE Letter. The results indicate what common sense would expect: decreasing outage time leads to increased availability and increased availability leads to increased generation and pollution. Ex. 2-G, DTE June 3, 2010 Letter; Ex. 8, Biewald Dec. ¶¶18, 21.

Monroe Unit 2 ran every hour it was available in the five years before the project. Ex. 5, Koppe Dec. ¶34. In the future, it will run during the additional, available hours recovered by replacing the worn out economizer and pendant reheater. *Id.* These additional hours are clearly related to the project.

Emissions Increase Based On Analysis Upheld In Prior Litigation[7]

The same relationship between outage time, availability, and generation that is reflected in DTE's PROMOD modeling is the foundation of the United States' emissions analysis set forth in the declarations of Robert Koppe and Ranajit Sahu. The analysis is founded on the common sense premise – reflected in Defendants' own documents – that replacing major boiler components, such as economizers and reheaters, that have deteriorated and are causing outages will result in greater unit availability. When a unit is available to run more, particularly when the unit is considered "base load," it will be called on to generate more electricity. This is true for Monroe Unit 2. Ex. 8, Biewald Dec. ¶15. Greater generation in turn typically means additional pollution. *See, e.g., United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 869, 878-81 (S.D. Ohio 2003). Plaintiff's expert witness Myron Adams worked in generation planning at American Electric Power, the nation's largest electric utility, for four decades, and stresses that the primary purpose of replacing boiler components like those at issue is to increase the unit's generation, thus allowing the utility to produce more electricity and/or decrease its power production costs by running cheaper units like Monroe Unit 2 more. Ex. 10, Declaration of Myron Adams ("Adams Dec.") ¶¶9, 12-15; *see also* Ex. 11, Declaration of Matthew Kahal

[7] Because DTE's own projected increase and the company's inability to show that it qualifies for the exclusion establish liability, the Court need not consider the parallel analysis presented by the United States. In prior litigation, the defendants had not done the analysis found here in the Notice Letter, so plaintiffs performed their own analysis.

("Kahal Dec.") ¶¶12-13. The projects pay for themselves through increased generation. Ex. 10, Adams Dec. ¶¶13-15.

Mr. Koppe, who has studied the availability of coal-fired power plants for more than three decades as a consultant for industry and the government, determined that the pendant reheater and economizer had reached the end of their productive life and had been causing outages of the unit throughout the five years before the project. Ex. 5, Koppe Dec. ¶¶61, 116. For the baseline periods selected by DTE, the pendant reheater and economizer prevented the units from operating for 724 hours for the SO_2 baseline period and 908 hours for the NO_X baseline period. *Id.* ¶92. Mr. Koppe further concluded that the replacement would eliminate those outages in the future, allowing the unit to run those additional hours. *Id.* ¶61. These conclusions are supported by DTE's own documents. As described above, the project justification documents set forth the poor condition of the old components and the expectations for avoiding related outages in the future. DTE expected that the time lost due to outages would drop by nearly half after the project. *Id.* ¶89. DTE then used the PROMOD model to forecast the effect of reducing the unit's forced outages and the results showed improved availability and increased generation from Unit 2. Ex. 8, Biewald Dec. ¶21.

Dr. Sahu took Mr. Koppe's analysis and calculated the additional pollution that would be generated by Unit 2 operating additional hours thanks to the new components. Dr. Sahu's calculations projected an increase of 1,382 tons of SO_2 and 735 tons of NO_X. Ex. 3, Sahu Dec. ¶¶10. While these increases are lower than those projected by DTE in the Notice Letter, the calculation is intentionally conservative in several respects. *See* Ex. 5, Koppe Dec. ¶¶23-32, 110. In addition, the entirety of the predicted increase set forth by Dr. Sahu is related to the project because it is based solely on the additional generation allowed by recovering outage

hours caused by the specific components replaced. *Id.* ¶28. Accordingly, there is no basis for excluding any portion of this projected actual emissions increase.

B. The Failure To Follow NSR Is Causing Irreparable Harm To The Public

The unpermitted pollution from Monroe Unit 2 is harming the health of people downwind of the plant, causing premature death, heart attacks, and respiratory problems, among other health effects. This health proof is based on the scientific consensus and has been endorsed by the only court to hear a NSR remedy case. *United States v. Cinergy Corp.,* 618 F. Supp. 2d 942 (S.D. Ind. 2009); *see generally* Ex. 12, Declaration of Joel Schwartz ("Schwartz Dec.").

From the moment it resumed operation after the project, Monroe Unit 2 has been generating much more pollution than the law allows. NSR requires a modified source to install state-of-the-art pollution controls. For a coal-fired unit like Unit 2, such controls would reduce the emissions of NO_X and SO_2 by 90% to 99%. Ex. 3, Sahu Dec. ¶¶18-19; *Cinergy*, 618 F. Supp. 2d at 955 (finding current best available control technology requirement was pollution controls that could remove 90% of NO_X and 99% of SO_2). If Defendants had complied with the law, those controls would eliminate at least 7,942 tons of NO_X and 26,525 tons of SO_2 each year. Ex. 3, Sahu Dec. ¶¶18-19. Eliminating that much SO_2 would be the equivalent of removing 371,000 heavy-duty trucks from the road – all the heavy-duty trucks registered in Michigan, Illinois, Ohio, and Indiana combined. Ex. 1, Chinkin Dec. ¶7. The excess NO_X emissions are the equivalent of 1 million passenger cars, a quarter of all the cars in Michigan. *Id.* The Monroe Unit 2 excess emissions are larger than those from the *Cinergy* case, where the court ordered injunctive relief that included shutting the units down within four months of its decision. *See Cinergy*, 618 F. Supp. 2d at 949.

These excess emissions of NO_X and SO_2 mix with other pollutants in the air to form PM2.5. Ex. 1, Chinkin Dec. ¶8; *Cinergy*, 618 F. Supp. 2d at 949. Consisting of tiny particles that are dwarfed by a human hair, PM2.5 can be inhaled and lodges deep in the lung. Ex. 12, Schwartz Dec. ¶13; Ex. 1, Chinkin Dec. ¶8; *Cinergy*, 618 F. Supp. 2d at 949. The scientific community, including the American Medical Association and the American Cancer Society, has determined that PM2.5 causes health impacts including increased respiratory ailments, heart attacks, and premature mortality. *Cinergy*, 618 F. Supp. 2d at 949-50 (listing scientific and medical groups in agreement); *Am. Farm Bureau Fed'n v. E.P.A.*, 559 F.3d 512, 515 (D.C. Cir. 2009) ("Studies have demonstrated that both fine and coarse PM can have negative effects on public health and welfare. For example, each is associated with increased mortality (premature death) rates and morbidity (illness) effects such as cardiovascular disease and decreased lung function."). Studies also demonstrate that PM2.5 causes decreased lung function and increased instances of chronic bronchitis, stroke, and hospitalizations for heart attacks and respiratory problems. Ex. 12, Schwartz Dec. ¶¶48, 52, 87-88, 91. The health impacts from PM2.5 are linear, so that any decrease in PM2.5 will improve health. *Id.* ¶¶76-77, 82; *Cinergy*, 618 F. Supp. 2d at 950. As another court found in granting injunctive relief against coal-fired power plants in a recent public nuisance case, "PM2.5 exposure has significant negative impacts on human health, even when the exposure occurs at levels at or below the NAAQS." *North Carolina v. Tenn. Valley Auth.,* 593 F. Supp. 2d 812, 821 (W.D.N.C. 2009) *rev'd on other grounds*, No. 09-1623, --- F.3d ----, 2010 WL 2891572 (July 26, 2010). In *Cinergy*, the court found that a smaller amount of excess emissions than that at issue here "has a significant impact on human health" in several states surrounding the plant. *Cinergy*, 618 F. Supp. 2d at 963.

The unpermitted SO_2 and NO_X emissions from Monroe Unit 2 are harming downwind communities. Epidemiologist Dr. Joel Schwartz is a tenured professor at the Harvard School of Public Health and Harvard Medical School, a recipient of the MacArthur Fellowship, and the most cited author worldwide in the air pollution field. Ex. 12, Schwartz Dec. ¶1. Dr. Schwartz estimated that the unpermitted emissions from Monroe 2 will cause approximately 90 premature deaths per year – one death every four days – in the communities downwind of the plant, based on estimates of harm from power plant emissions published in a peer-reviewed scientific paper. *Id.* ¶¶116-120.

The Monroe Unit 2 NO_X and SO_2 excess emissions increase PM2.5 concentrations across a swath of the Midwest, including metropolitan areas such as Detroit and Cleveland where the air quality already falls short of the NAAQS, the standard set by EPA to protect public health. Ex. 1, Chinkin Dec. ¶12; 42 U.S.C. § 7409. Increasing the concentration of pollution with unpermitted emissions in areas already found to be out of compliance with federal standards is sufficient to establish irreparable harm. *See Ohio Valley Envtl. Coalition v. Hobet Mining, LLC*, No. 3:09-1167, -- F. Supp. 2d --, 2010 WL 2739990, at *28-29 (S.D.W.Va. July 12, 2010) (finding injunctive relief appropriate based on violation of Clean Water Act permit). The impact from Monroe Unit 2 on PM2.5 concentrations is similar to the impact in the *Cinergy* case, where the court found that injunctive relief, including shutdown, was necessary.

There can be little doubt that Monroe Unit 2's unpermitted emissions are causing irreparable harm. As the Supreme Court has stated, "Environmental injury, by its nature, can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable." *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987). The

damage to people's lives and health cannot be undone, highlighting the importance of prompt preliminary relief that avoids such harms.

C. The Equities Favor Injunctive Relief

The burden on DTE from the relief the United States proposes is minor compared to the severe harm the public is suffering. The United States proposes a remedy that fully mitigates and offsets the illegal pollution from Monroe Unit 2 in a manner that minimizes the burden imposed on Defendants.

1. Plaintiff's Proposed Relief

Now that its grandfathered status under the law has ended, Monroe Unit 2 is emitting tens of thousands of tons of pollution more per year than is allowed by law, at a tremendous cost to the public health. At best, it will take three to four years to obtain the NSR permits and install the state-of-the-art pollution controls necessary for Monroe Unit 2 to return to compliance with the law. Sitting in equity, the Court's charge is the "prevention of injury by a proper order." *Stenberg v. Cheker Oil Co.*, 573 F.2d 921, 925 (6th Cir. 1978). Here preventing injury requires finding a way to avoid the harm to public health by eliminating or offsetting the unpermitted pollution.

The simplest way to prevent the harm from Monroe Unit 2's unpermitted pollution would be to shut the unit down until it complies with NSR. The shutdown remedy lies within the Court's broad equitable authority, was ordered in *Cinergy* for a coal-fired power plant that violated NSR, and would provide a powerful incentive for DTE to comply as soon as possible. However, that remedy might create more factual issues for the parties to litigate. Rather than litigate the alleged hardships from shutdown at this time, the United States proposes a preliminary injunction that requires Defendants to:

- Begin the process of obtaining NSR permits for the Monroe Unit 2 modification; and
- Apply interim pollution controls or otherwise reduce emissions from other DTE coal-fired units in order to mitigate the emissions from Monroe Unit 2.

Requiring DTE to begin the permitting process now will minimize the duration of the irreparable harm from Monroe Unit 2 by ensuring that the permit is obtained as soon as possible. This will impose minimal burden on Defendants: the cost and effort to obtain a permit is not significant compared to the costs of installing the FGD that Defendants have already said they will install. Ex. 3, Sahu Dec. ¶20; Ex. 2-B.

Requiring DTE to mitigate the Monroe Unit 2 pollution with reductions at its coal-fired units will ensure that the public will not suffer from Defendants' failure to comply with the law. While the state-of-the-art pollution controls ultimately required by law at Monroe Unit 2 will take up to four years to install, Defendants could use other standard SO_2 and NO_X reduction techniques that could be operating in less than a year. Because Defendants' coal-fired power plants are all in eastern Michigan, reductions at other facilities will largely benefit the same communities harmed by Monroe Unit 2's pollution. For instance, the Trenton Channel Plant is only 18 miles away from Monroe, and tends to affect the same area, based on modeling of the two plants' emissions. Ex. 1, Chinkin Dec. ¶20. A preliminary injunction that required Defendants to offset the Monroe Unit 2 unpermitted pollution would avoid the 90 deaths per year, and other harm to public health, that would otherwise be caused by Defendants' failure to comply with the law. This reduction in pollution would provide the benefit of NSR to the communities downwind of Monroe Unit 2.

While the United States believes that DTE could be allowed to decide the most efficient way to offset the Monroe Unit 2 pollution, subject to EPA's review and approval, we propose

one set of measures in order to illustrate what could be required. Defendants could use the NO_X removal technology known as selective non-catalytic reduction ("SNCR") and the SO_2 removal technology known as dry sorbent injection. Both of these methods could be operating within nine months. Ex. 3, Sahu Dec. ¶22. While their effectiveness varies based on the operating conditions, it is reasonable to assume that dry sorbent injection could remove 65% of the SO_2 from Defendants' units, while SNCR could remove 25% of the NO_X. *Id.* ¶¶22, 24. Installing these controls at Belle River Units 1 and 2 and Trenton Channel Unit 9A would result in the elimination of about 29,898 tons of SO_2 and 3,268 tons of NO_X per year. *Id.* ¶¶24-25. The total reduction would offset nearly the entire Monroe Unit 2 unpermitted emissions, and the remaining emissions could be made up through minor operational changes.[8] *Id.* ¶¶22, 25. This example case could be expected to require $39 million in capital spending and $14 million in annual operating costs. *Id.* ¶25. The total annual cost to Defendants of this illustrative program, after spreading the capital cost over several years per typical practice, would be about $19 million per year. Ex. 11, Kahal Dec. ¶14. It is possible that Defendants, given their greater knowledge of the details of their system, could achieve the same reductions at significantly less cost.

This type of preliminary relief is intended to expeditiously provide the benefit to the public required by NSR at the minimum cost. Importantly, the United States is *not* asking for state-of-the-art controls at Monroe Unit 2 at this time; any order on such permanent relief to bring the unit into compliance with NSR will await the Court's final decision on the merits. Nor is the United States demanding the shutdown of Unit 2 until such controls are installed. Instead,

[8] This particular reductions program yields greater SO_2 reduction and less NO_X reduction than the Monroe Unit 2 excess emissions. The benefit to the environment will be similar to eliminating the unpermitted emissions, since SO_2 and NO_X have similar effects and SO_2 can be more damaging, depending on the circumstances. Ex. 12, Schwartz Dec. ¶118-119; Ex. 1, Chinkin Dec. ¶21.

the United States' proposed preliminary relief allows the flexibility to reduce emissions at other coal-fired units in Michigan, thus minimizing the burden on Defendants.

2. The Harm Avoided by Injunctive Relief Outweighs any Hardship to Defendants

The cost to Defendants of offsetting the illegal pollution from Monroe Unit 2 is vastly outweighed by the harm to the public if no relief is granted.

An interim, cost effective emissions reduction program can be fashioned that will not pose a significant hardship to Defendants or their customers. To put the cost of the interim controls described above in perspective, Defendant Detroit Edison had an operating cash flow of more than $1 billion in 2009 and paid a $305 million dividend to parent DTE. Ex. 11, Kahal Dec. ¶¶7, 15. Matthew Kahal, an independent economist specializing in energy economics, testifies that the cost of offsetting the Monroe Unit 2 emissions will not harm DTE or its customers. Ex. 11, Kahal Dec. ¶¶15-16. Moreover, by reducing NO_X, SO_2, and mercury emissions, the pollution reduction program will lessen Defendants' costs of complying with other regulatory programs. Ex. 3, Sahu Dec. ¶26.

The cost of an interim emissions reduction program will also be minimal compared to the $65 million cost of the Unit 2 overhaul or the ultimate cost of state-of-the-art pollution controls at the unit. Defendants have stated that installing SCR and FGD at Monroe Unit 2 would cost about $630 million. Ex. 3, Sahu Dec. ¶20; Ex. 2-B. In November 2009, the company announced that it was going ahead with those pollution controls, though it now says it has no plans to install SCR. Ex. 2-B; Ex. 2, Chatfield Dec. ¶17. The cost of the interim relief requested by the United States could be achieved for about 6% of the total SCR and FGD cost that Defendants expected to incur less than a year ago.

Finally, and most importantly, the cost of the pollution reduction pales in comparison to the human health impact without preliminary relief. As described above, the unpermitted pollution from Monroe Unit 2 is causing a spectrum of health impacts, including premature mortality. It is unjust for anyone breathing the air downwind of the Monroe plant to die or get sick because Defendants flouted the law. Even if one were to view the health effects of defendant's violations through an economic lens, the cost to public health dwarfs the burden of the remedy here. Based on studies that measure how much a person would spend to avoid a risk of death, economists have estimated the value of a human life for the purpose of regulatory cost-benefit analyses. Ex. 12, Schwartz Dec. ¶¶116-117. EPA has used approximately $6 million per death as its benchmark in evaluating air pollution reduction programs. *See, e.g.*, 75 Fed. Reg. 45,210, 45,349 (Aug. 2, 2010) (proposed regional rule to reduce PM2.5 and ozone; using value of $6.3 million per life in year 2000 dollars). By this measure, the benefit from saving 90 lives per year can be estimated at $540 million per year – dramatically outweighing the roughly $19 million annual cost to Defendants of the interim pollution reduction program outlined above. Ex. 12, Schwartz Dec. ¶¶116-120; Ex. 11, Kahal Dec. ¶14.

3. Plaintiff's Proposed Relief Implements the Congressional Purpose of New Source Review

As described above, the balance of the equities favors the injunction proposed by the United States: the harm from Monroe Unit 2's pollution is much greater than the burden to mitigate that pollution. The United States' proposed relief is further supported by the Congressional intent behind NSR.

In 1977, Congress crafted a grand bargain: existing sources would not have to immediately install state-of-the-art pollution controls, but they would eventually have to install controls or shutdown as they aged. Monroe Unit 2 has enjoyed the fruits of this bargain for more

than three decades of operation – throughout its entire original expected lifetime – without advanced pollution controls. Now the unit has reached the critical point established by Congress: Defendants modified the unit and so must reduce emissions by using state-of-the-art pollution controls. 42 U.S.C. § 7475(a). While the Court retains its equitable discretion in selecting the appropriate injunctive relief, "Courts of equity cannot, in their discretion, reject the balance that Congress has struck in a statute." *United States v. Oakland Cannabis Buyers' Co-op.,* 532 U.S. 483, 497-98 (2001). Congress required steep emissions reductions at precisely this point; the United States' proposed injunction yields just such reductions while minimizing the impact on Defendants.

Such injunctive relief is particularly appropriate given the "extraordinary weight courts of equity place upon the public interests in a suit involving more than a mere private dispute . . . and from the deference courts afford the political branches in identifying and protecting the public interest." *United States v. Marine Shale Processors*, 81 F.3d 1329, 1359 (5th Cir. 1996) (citing *Georgia v. Tennessee Cooper Co.*, 206 U.S. 230, 237-38 (1907); *Virginian Ry. v. Sys. Fed'n No. 40, AFL*, 300 U.S. 515, 552 (1937)); *see also United States v. Miami Univ.*, 294 F.3d 797, 819 (6th Cir. 2002) ("Courts of equity may, and frequently do, go much farther both to give and withhold relief in furtherance of the public interest than they are accustomed to go when only private interests are involved.") (quoting *Virginian Railway*, 300 U.S. at 552).

In this case, like in *Cinergy*, "an order requiring Defendants to take actions that remedy, mitigate, and offset harms caused to the public and the environment by their past CAA violations would seem to give effect to the CAA's purpose 'to protect and *enhance* the quality of the Nation's air resources so as to promote the public health and welfare.'" *United States v. Cinergy Corp.*, 582 F. Supp. 2d 1055, 1061-62 (S.D. Ind. 2008) (citing 42 U.S.C. § 7401 (emphasis

supplied by *Cinergy* court)). Both the balance of equities between the parties and the Congressional purpose of enhancing air quality favor preliminary relief here.

CONCLUSION

When Monroe Unit 2 reached its original life expectancy and major boiler components began wearing out, DTE embarked on a $65 million overhaul to significantly improve unit operations. This is precisely the moment Congress intended that existing units would have to install state-of-the-art pollution controls. Defendants have failed to comply with the law, and the direct result of that failure is unpermitted pollution harming the public health. Sitting in equity, this Court's charge is the "prevention of injury by a proper order." *Stenberg v. Cheker Oil Co.*, 573 F.2d 921, 925 (6th Cir. 1978). The United States respectfully requests that the Court minimize the harm from Monroe Unit 2's unpermitted pollution by ordering emissions reductions to make up for the pollution that Monroe Unit 2 should not be generating. Such an order brings the long-awaited benefits of New Source Review to the communities in Michigan and surrounding states affected by Monroe Unit 2's pollution.

Respectfully submitted,

IGNACIA S. MORENO
Assistant Attorney General
Environment & Natural Resources Division

Dated: August 6, 2010

/s/ Thomas A. Benson
JUSTIN A. SAVAGE
Senior Counsel
THOMAS A. BENSON (MA Bar # 660308)
Trial Attorney
Environmental Enforcement Section
Environment & Natural Resources Division
U.S. Department of Justice
P.O. Box 7611
Washington, D.C. 20530

(202) 514-5261
thomas.benson@usdoj.gov

BARBARA McQUADE
United States Attorney
Eastern District of Michigan

ELLEN CHRISTENSEN
Assistant United States Attorney
Eastern District of Michigan
211 W. Fort St., Suite 2001
Detroit, MI 48226

OF COUNSEL:
SABRINA ARGENTIERI
MARK PALERMO
SUSAN PROUT
Associate Regional Counsel
United States Environmental
Protection Agency, Region 5
77 W. Jackson Blvd.
Chicago, IL 60604

APPLE CHAPMAN
Attorney Adviser
United States Environmental
Protection Agency
1200 Pennsylvania Ave. NW
Washington D.C. 20460

CERTIFICATE OF SERVICE

I hereby certify that on August 6, 2010, the foregoing "Motion for Preliminary Injunction" and the memorandum in support were filed electronically using the Court's ECF system and were also served by electronic mail (with exhibits served by FedEx) upon the following persons:

Michael J. Solo, Jr.
DTE Energy Co.
One Energy Plaza
Detroit, MI 48226-1279
solom@dteenergy.com

F. William Brownell
James W. Rubin
Hunton & Williams LLP
1900 K Street, NW
Washington DC 20006
bbrownell@hunton.com
jrubin@hunton.com
Attorneys for Defendants

s/ Thomas A. Benson
Counsel for the United States

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	)	
	)	
	)	
Plaintiff,	)	Civil Action No. 2:10-cv-13101-BAF-RSW
	)	
v.	)	Judge Bernard A. Friedman
	)	
DTE ENERGY COMPANY, and	)	Magistrate Judge R. Steven Whalen
DETROIT EDISON COMPANY	)	
	)	
	)	
Defendants.	)	
	)	

MEMORANDUM IN SUPPORT OF
PLAINTIFF'S MOTION FOR PRELIMINARY INJUNCTION

APPENDIX A:
LIST OF EXHIBITS

1. Declaration of Lyle Chinkin
2. Declaration of Ethan Chatfield
   A. June 3, 2010 Notes from M. Ackerman and E. Chatfield (U.S. EPA) of June 2, 2010 Monroe Generating Station Inspection
   B. December 8, 2009 DTE Energy Press Release entitled, "DTE Energy Environmental Project Will Create 900 Jobs"
   C. March 12, 2010 Letter from Kelly Guertin (DTE Energy) to William Presson (Michigan Department of Environmental Quality)
   D. April 22, 2010 Article by Charles Slat from "The Monroe Evening News" entitled, "Extreme makeover: Power plant edition"
   E. June 4, 2010 Notice and Finding of Violation issued to DTE Energy Co. and Detroit Edison Co.
   F. Excerpts of DTE Documents Produced in Response to Request During EPA's June 2, 2010 Inspection of Monroe Generating Station (CBI) (FILED UNDER SEAL)
   G. June 3, 2010 Letter from Michael Solo (DTE Energy) to Mark Palermo (U.S. EPA) enclosing Detroit Edison response to June 2, 2010 CAA Section 114 Information Request
   H. Direct Testimony of Paul Fessler before Michigan Public Service Commission, Case No. U-15768

I. May 28, 2010 Letter from Phillip Brooks (U.S. EPA) to Michael Solo (DTE Energy) requesting information pursuant to CAA Section 114

J. June 4, 2010 Letter from Phillip Brooks (U.S. EPA) to Michael Solo (DTE Energy) requesting information pursuant to CAA Section 114

3. Declaration of Dr. Ranajit Sahu

   A. November 16, 2009 DTE Energy Press Release entitled, "Second Scrubber Continues Downward Emissions Trend at Detroit Edison's Monroe Power Plant"

4. May 23, 2000 Letter from Frank Lyons (U.S. EPA) to Henry Nickel (Hunton & Williams) ("Applicability Determination")

5. Declaration of Robert H. Koppe

6. Declaration of A. Michael Hekking

7. September 9, 1988 Memo from Don Clay (U.S. EPA) to David Kee (U.S. EPA)

8. Declaration of Bruce Biewald

9. *United States v. Cinergy Corp.*, 1:99-cv-01693-LJM-JMS (S.D. Ind.), Final Jury Instructions, Dkt. 1535, May 21, 2008

10. Declaration of Myron Adams

11. Declaration of Matthew Kahal

12. Declaration of Dr. Joel Schwartz

Exhibit 1

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	)	
	)	
	)	
Plaintiff,	)	Civil Action No.
	)	
v.	)	
	)	
DTE ENERGY COMPANY, and	)	
DETROIT EDISON COMPANY	)	
	)	
	)	
Defendants.	)	
	)	

Declaration of Lyle Chinkin

I, Lyle Chinkin, declare as follows:

1. I am the President of Sonoma Technology, Inc. ("STI"), which specializes in air quality and meteorological research and services. I joined STI in 1992 and have worked on projects for federal, state, and local government agencies; universities; public and private research consortiums; and major corporations. My resume is attached as Exhibit A.

2. I received Master of Science (1984) and Bachelor of Science (1981) degrees in Atmospheric Sciences from the University of California at Davis.

3. I have over 20 years of experience in professional consulting regarding air quality and over five years of experience at the California Air Resources Board. I have been appointed to and served on the National Research Council of the National Academy of Sciences Committee on the Effects of Changes in New Source Review Programs for Stationary Sources of Air Pollutants. I have also been appointed to and served on a panel

to review "Improving Emission Inventories for Effective Air Quality Management Across North America, a NARSTO Assessment". I have also served as a United States Environmental Protection Agency (EPA) invited peer-reviewer of the EPA particulate matter (PM) National Ambient Air Quality Standards (NAAQS) Criteria Document, an expert panel member for the review of the Valdez Air Health Study, and as an expert witness for the United States Department of Justice (DOJ) in environmental enforcement actions. My resume is Appendix A to this declaration, a list of publications is found at Appendix B, and my compensation for this matter is provided at Appendix C. My testimony as an expert witness is listed at Appendix D.

4. On behalf of EPA, DOJ has requested an analysis of the estimated air quality impacts associated with excess emissions from Unit 2 of DTE Energy's Monroe coal-fired power plant located in Monroe, Michigan. My conclusions are still being developed, and could be affected by information or analysis that has yet to be produced. Thus, these conclusions do not represent my final opinions, but rather a reasonable preliminary description of my opinions in this case. A list of documents considered in forming these opinions is provided at Appendix E to this declaration.

5. DTE Energy's Monroe power plant is the eleventh largest coal fired plant in the United States, with 4 generating units providing a total output of over 3,100 megawatts (MW).[1] In 2005, the Monroe power plant was also the eleventh largest sulfur dioxide (SO_2) emitter in U.S., emitting a total of 110,306 tons of SO_2. Though emissions control systems have been installed on other units at the Monroe power plant, Unit 2, an 823 MW unit, is currently uncontrolled. In 2009, Monroe Unit 2 emitted 27,230 tons of SO_2 and

[1] Based on power plant rankings published by the U.S. Energy Information Administration (see http://www.eia.doe.gov/neic/rankings/plantsbycapacity.htm).

8,205 tons of NO_x, making it the largest individual (i.e., unit level) source of both pollutants in the state of Michigan that year. And on average, this unit has emitted 26,403 tons per year (tpy) of SO_2 and 9,618 tpy of oxides of nitrogen (NO_x) since 2000. Figures 1 and 2 show annual variations in SO_2 and NO_x emissions for Unit 2 of the Monroe plant for years 2000 through 2009, as measured by continuous emissions monitoring.

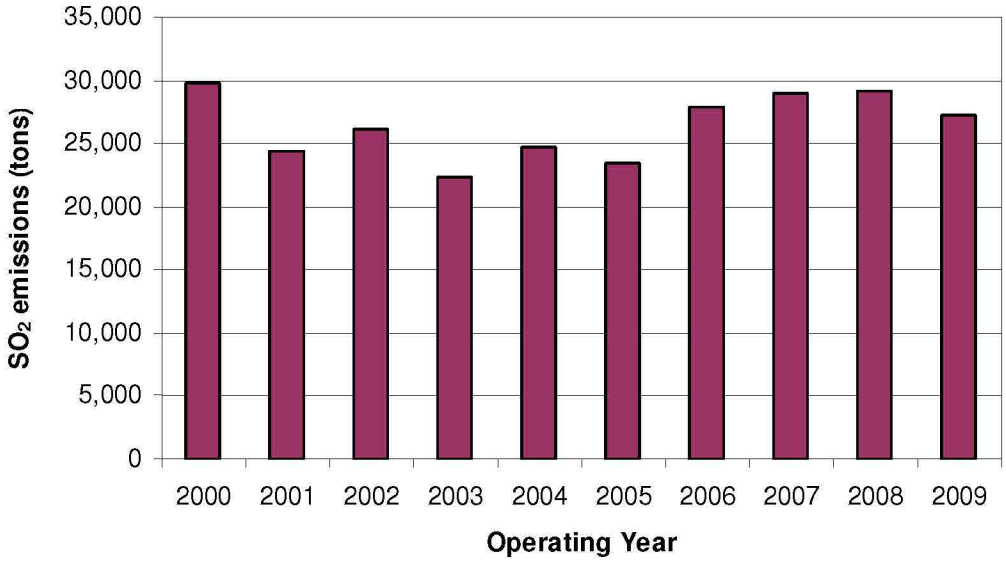

Figure 1. Historical SO_2 emissions from Unit 2 of the Monroe power plant.

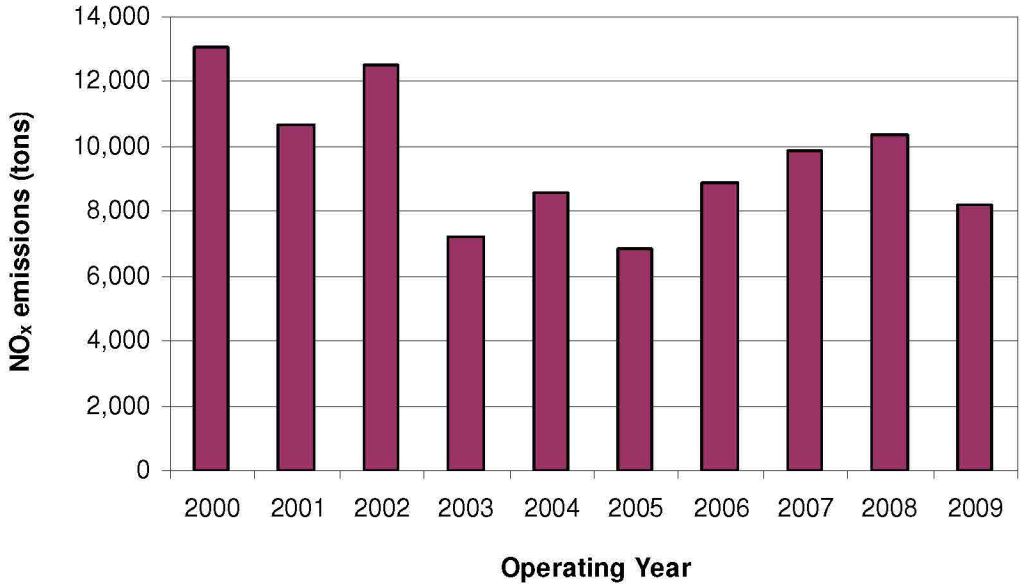

Figure 2. Historical NO_x emissions from Unit 2 of the Monroe power plant.

6. I understand that DTE Energy made significant modifications to Monroe Unit 2 in 2010 which should have triggered New Source Review ("NSR") for SO_2 and NO_x at Unit 2. If NSR had been conducted at the time of these modifications, pollution controls would have been required on these units. The installation of pollution control technologies on Unit 2 at the time of its modifications could have reduced the emissions of SO_2 by 95% or more and NO_x by 90% or more from that point forward, compared to emissions that were actually released. The amount of emissions in excess of what would have been emitted with pollution controls is referred to as "excess emissions." Based on the most recent annual emissions data for Monroe Unit 2 (year 2009), we modeled excess emissions from Unit 2 of to 25,869 tons of SO_2 and 7,384 tons of NO_x per year, which we understand to be a conservative estimate of emissions. These estimates are in keeping with historical emissions from Monroe Unit 2, which has emitted 26,403 tons per year of SO_2 and 9,618 tons per year of NO_x, on average, over the past 10 years.

7. To place the excess emissions from Monroe Unit 2 in context, I made the following comparisons between the excess emissions cited above and other sources in the region identified in EPA's 2005 National Emissions Inventory (NEI).

- Based on 2009 emissions, the excess SO_2 emissions (25,869 tons) are equivalent to the annual emissions of 371,000 heavy-duty (HD) trucks, or all the trucks registered in Michigan, Illinois, Ohio and Indiana combined (see **Figure 3**).
- The excess SO_2 emissions at Monroe Unit 2 are equivalent to the 6th largest point source in Michigan (out of 1614 point sources in the 2005 NEI) – If all Monroe emissions are considered, it is the largest point source in Michigan.
- The largest non-utility point source of SO_2 in the Detroit-Ann Arbor nonattainment area is the Holcim facility in Monroe, Michigan, one of the nation's largest manufacturers and distributors of cement and mineral products. The Holcim plant emitted 7,129 tons of SO_2 in 2005, making the excess SO_2 emissions from Monroe Unit 2 equivalent to the output of more than 3 Holcim plants.
- The excess SO_2 emissions at Monroe Unit 2 are more than the SO_2 emissions from all 405 non-EGU point sources in the Detroit-Ann Arbor nonattainment area combined.
- The largest non-utility point source of SO_2 in city of Detroit is the United States Steel Corp Great Lakes Works, which emitted 4,431 tons of SO_2 in 2005. The excess emissions at the Monroe Unit 2 are equivalent to the output of five United States Steel Corp Great Lakes Works plants.
- The largest non-utility point source of SO_2 in Cleveland is the DiGeronimo Aggregates facility, a producer of concrete aggregates, which emitted 841 tons of SO_2 in 2005. The excess emissions at the Monroe Unit 2 are equivalent to the output of 30 DiGeronimo Aggregates facilities.
- The excess NO_x emissions at Monroe Unit 2 are equivalent to the emissions of about 1 million passenger cars, or one quarter of all passenger cars registered in Michigan (see **Figure 4**).
- The excess NO_x emissions at Monroe Unit 2 are equivalent to the 7th largest point source in Michigan (out of 1614 point sources in the 2005 NEI) – If all Monroe emissions are considered, it is the largest source.
- The largest non-utility point source of NO_x in the Detroit-Ann Arbor nonattainment area is the United States Steel Corp Great Lakes Works in Wayne, Michigan, which emitted 3,290 tons of NO_x in 2005. The excess NO_x emissions from Monroe Unit 2 are equivalent to the output of more than two United States Steel Corp Great Lakes Works plants.

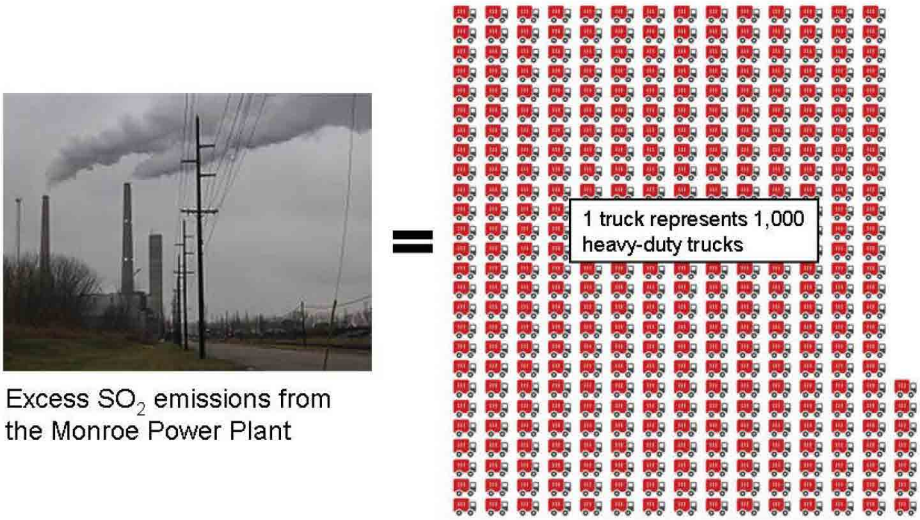

Figure 3. The excess SO_2 emissions from the Monroe Unit 2 are equal to the SO_2 emissions from 371,000 heavy-duty trucks or all of the heavy-duty trucks registered in Michigan, Illinois, Ohio, and Indiana combined.

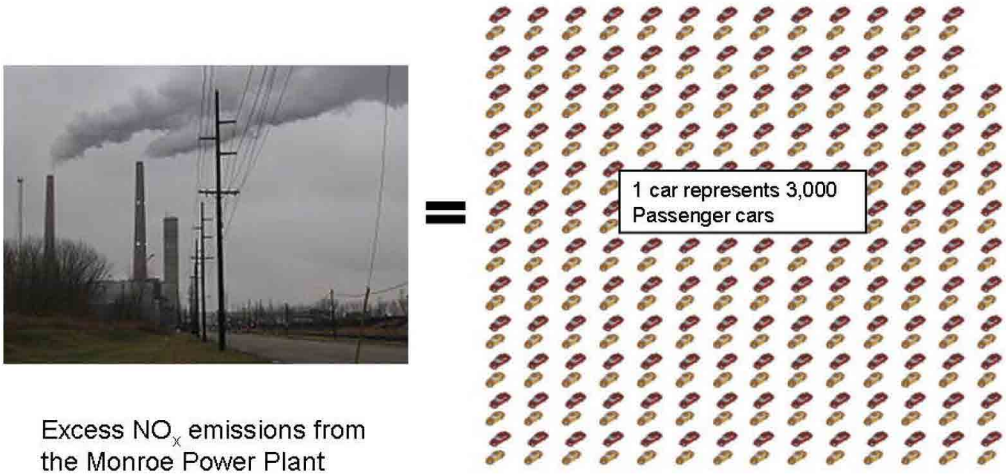

Figure 4. The excess NO_x emissions from the Monroe Unit 2 are equal to the NO_x emissions from about 1 million passenger cars or one quarter of all passenger cars registered in Michigan.

8. The emissions of SO_2 and NO_x from Monroe Unit 2 form sulfate and nitrate particles, respectively, which contribute to the secondary formation of fine particulate matter (PM) in the atmosphere. Secondary PM forms when precursor gases undergo chemical and physical transformations in the atmosphere. (Primary PM, on the other hand, is directly emitted into the atmosphere and includes suspended dust, sea salt,

organic carbon, elemental carbon, metals from combustion, and small amounts of sulfate and nitrate.) In particular, SO_2 emissions form sulfate particles which, along with carbon, dominate the composition of $PM_{2.5}$ throughout the eastern United States. In addition, PM is a complex mixture of solid and liquid particles, with the size of particles in the atmosphere varying tremendously. Particle sizes are often classified in three size ranges:

- Ultra-fine particles (<0.1 μm),
- Fine particles (0.1 to 2.5 μm), and
- Coarse particles (2.5 to 10 μm).

where 1 μm is 1 millionth of a meter. When we refer to $PM_{2.5}$ we mean the concentration of particles that are less than 2.5 μm (i.e., particles in the fine and ultra-fine size ranges), while PM_{10} includes the sum of $PM_{2.5}$ and coarse particles. **Figure 5** provides a size comparison of $PM_{2.5}$ and PM_{10} particles to human hair and beach sand.

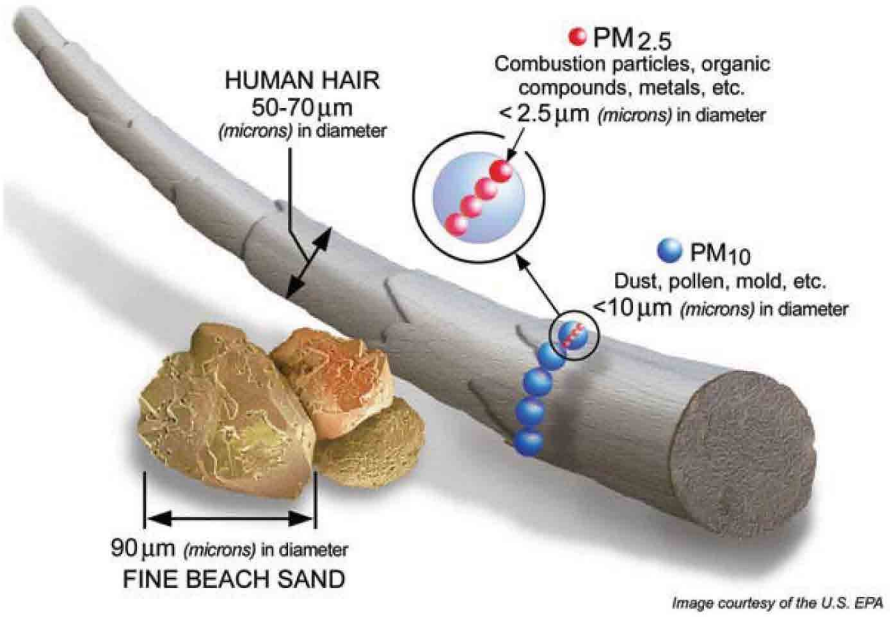

Figure 5. Size comparison of $PM_{2.5}$ and PM_{10} particles to human hair and beach sand.

9. Because of health effects associated with $PM_{2.5}$, EPA has established national ambient air quality standards (NAAQS) for $PM_{2.5}$ of 15 micro-grams per cubic meter ($\mu g/m^3$) for an annual average and 35 $\mu g/m^3$ for a daily average. However, EPA's Ambient Standards Group has recently released a draft policy assessment which concludes that consideration should be given to lowering annual $PM_{2.5}$ standard levels to the range of 11 to 13 $\mu g/m^3$, and that consideration should also be given to lowering the 24-hr (daily) $PM_{2.5}$ standard to 30 $\mu g/m^3$ in conjunction with an annual standard of 11 $\mu g/m^3$ (U.S. Environmental Protection Agency, 2010). These lower standards have been endorsed by the Clean Air Scientific Advisory Committee (CASAC), a key EPA advisory group (Williams, 2010). **Figure 6** shows areas currently classified as nonattainment based on the EPA's annual and 24-hr standards.

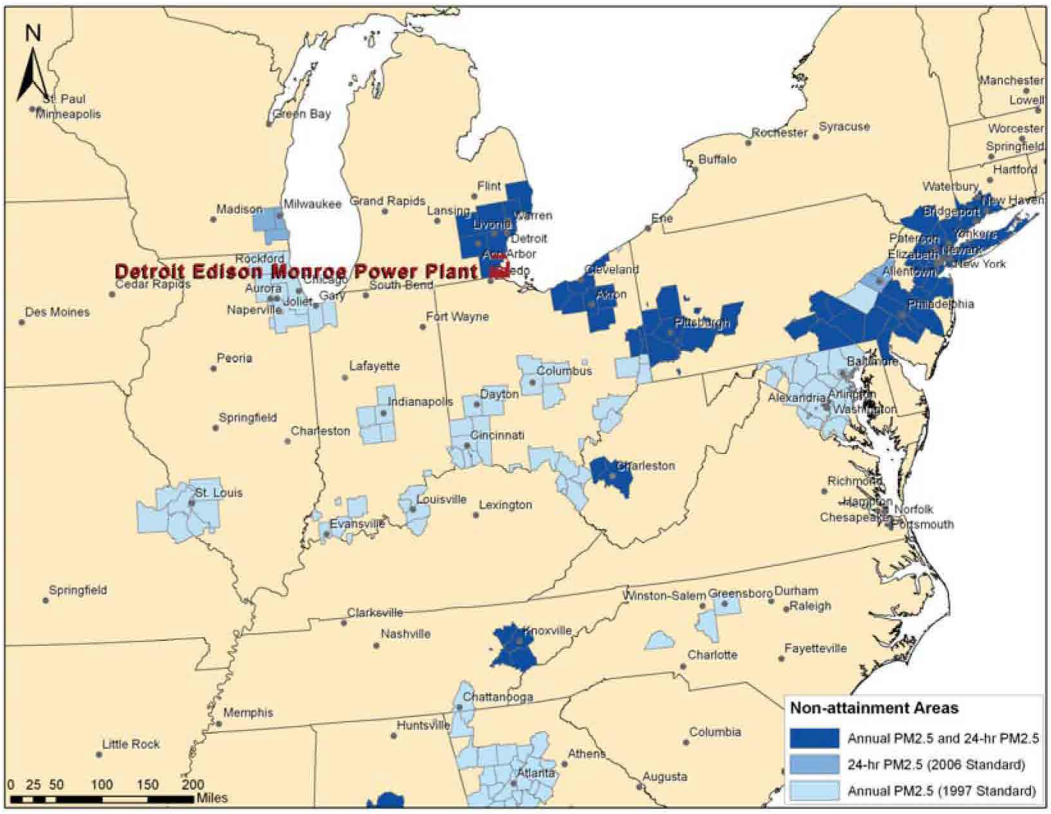

Figure 6. Annual and 24-hr $PM_{2.5}$ nonattainment areas in the region around the Monroe power plant.

10. The emissions of NO_x from the Monroe power plant form ozone in the lower atmosphere. Ozone is a secondary pollutant formed through the photochemical reactions of NO_x, volatile organic compounds (VOCs), and sunlight. The precursors to ozone (VOC and NO_x) are emitted into the atmosphere by both anthropogenic (man-made) and biogenic (naturally occurring) sources. Ozone in the lower atmosphere is an air pollutant with harmful effects on the respiratory systems of animals (including humans) and damaging to plants; however, the ozone layer in the upper atmosphere is beneficial, preventing potentially damaging ultraviolet light from reaching the Earth's surface. Because of health effects associated with ozone, EPA has established NAAQS for ozone, which is 75 parts per billion (ppb) for a peak 8-hour average. **Figure 7** shows areas

currently classified as nonattainment of this ozone standard and areas requiring ozone maintenance plans.

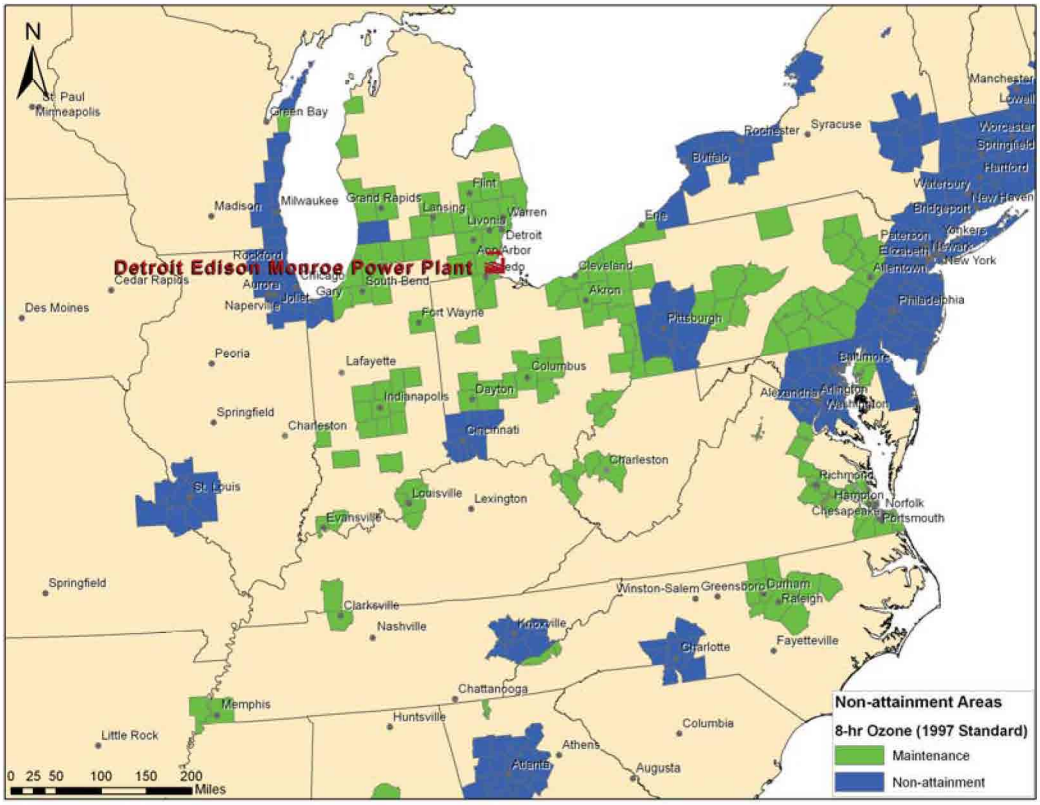

Figure 7. Ozone nonattainment and maintenance areas in the region around the Monroe power plant.

11. I reviewed the first six months of this year's (2010) ozone and $PM_{2.5}$ air quality data for nonattainment areas within 250 miles of the Monroe power plant. In the eastern and mid-western US most exceedances of the standards for these pollutants occur in the summer and autumn months. Even though it is early in the ozone and $PM_{2.5}$ year there have been numerous exceedances of the standards already. The number of exceedances is summarized in **Table 1**.

Area	Number of Days Exceeding the 24-hr $PM_{2.5}$ Standard	Number of Days Exceeding the Ozone Standard
Buffalo, NY	0	1
Pittsburg, PA	12	3
Cincinnati, OH	5	5
Cleveland, OH	28	3
Milwaukee, WI	6	2
Chicago, IL	6	3
Detroit, MI	1	2
Allegan, MI	0	0

Table 1. Summary of ozone and $PM_{2.5}$ exceedances days in nonattainment areas from January through June, 2010.

12. The excess SO_2 and NO_x emissions from the Monroe power plant contribute to the formation of $PM_{2.5}$ in nearby Detroit, throughout Michigan, in neighboring states, and in other states in the mid-eastern and eastern United States. Several of the areas impacted by the Monroe power plant are not in attainment of the NAAQS for $PM_{2.5}$, meaning that the excess emissions are adding to areas that already have unhealthy air quality levels. These areas include Detroit-Ann Arbor, Michigan, Cleveland-Akron-Lorain, Ohio, and Milwaukee-Racine, Wisconsin.

13. In consultation and coordination with colleagues at STI, I assessed the air quality impacts of the excess emissions from the Monroe power plant using an air quality model to better quantify these impacts. Air quality models are mathematical descriptions of pollution transport, dispersion, and related processes in the atmosphere and have been in use for decades and shown to be reliable. Air quality models estimate the air pollutant concentration at many locations, which are referred to as receptors. The number of receptors in a model far exceeds the number of monitors one could typically afford to deploy in a monitoring study. Therefore, models provide a cost effective way to analyze

impacts over a wide spatial area where factors such as meteorology, topography, chemistry, and emissions could be important. Air quality models are also appropriate tools to examine the air quality impacts of proposed regulations and policies. Air quality agencies and businesses regularly use these models to evaluate the sensitivity of air pollution concentrations to changes in emissions sources, which aids in decision making about emission control strategies. Predicting pollutant concentrations associated with future emission scenarios is another important use of air quality models.

14. Specifically, the state-of-the-science, peer-reviewed Comprehensive Air Quality Model with extensions (CAMx) model was used for this assessment. CAMx is an Eulerian photochemical model capable of simulating the emission, transport, diffusion, chemical transformation, and removal of gaseous and particle pollutants in the atmosphere on a three-dimensional array of grid cells (see **Figures 8 and 9**). Eulerian models are technically superior to and a more complete scientific representation of atmospheric processes than other models commonly used in air quality assessment and management, such as Gaussian and Lagrangian models, because they allow more comprehensive, explicit treatment of physical processes and include the interactions of numerous sources for chemical processes. Eulerian models operate on a computational grid (hence the term "grid models"), require sophisticated solution methods, and employ discrete time steps and operator splitting. These models rely on fewer assumptions but require high-speed computers and sophisticated numerical integration methods. Besides CAMx, other examples of Eulerian photochemical models include the Urban Airshed Model (UAM-IV and UAM-V), the Multiscale Air Quality Simulation Platform (MAQSIP), and the Community Multiscale Air Quality model (CMAQ). The ability of

Eulerian photochemical models to treat large numbers of sources and their chemical interactions makes them well suited for assessing the impacts of emission controls on urban and regional air quality. These models are reliable, having been used for over 25 years in developing State Implementation Plans (SIPs) for ozone under the Clean Air Act, and in the past seven years their use has been expanded to assessments of PM and hazardous air pollutants. Eulerian photochemical models are used worldwide, and both CAMx and CMAQ are widely used to support policy and regulatory decisions across the U.S. Example applications of CAMx include:

- Regional Haze/Visibility Modeling by various Regional Planning Organizations (RPOs), including the Visibility Improvement State and Tribal Associations of the Southeast (VISTAS), the Central Regional Air Planning Association (CENRAP), the Western Regional Air Partnership (WRAP), and the Midwest Regional Planning Organization (MRPO).
- Local PM modeling in support of the preparation of PM SIPs for St. Louis, Missouri and Boise, Idaho.
- Regional modeling (eastern U.S.) by EPA in support of analyses of EPA's Heavy-Duty Diesel Rule and Clean Air Interstate Rule (CAIR).
- BART modeling to evaluate the impact of best available retrofit technology (BART) controls at large stationary sources in Texas and Arkansas.

In addition, formal scientific reviews of the CAMx model have been widely carried out since the model was first introduced in the mid 1990s (Russell and Dennis, 2000; McNally and Tesche, 1998). More than two dozen governmental, academic, industrial, and private modeling groups have reviewed the model code as part of training, model set-up, performance evaluations, regulatory applications, and quality assurance activities.

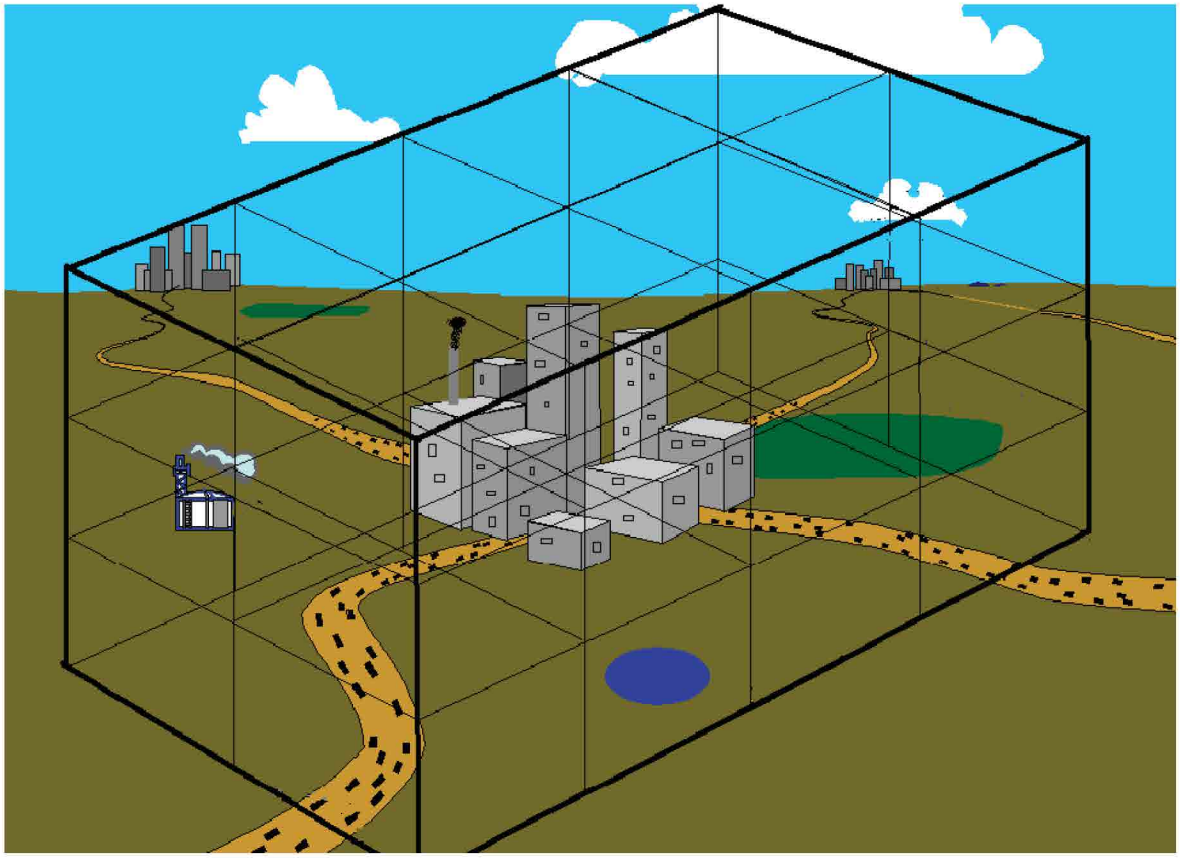

Figure 8. Photochemical grid model conceptualization.

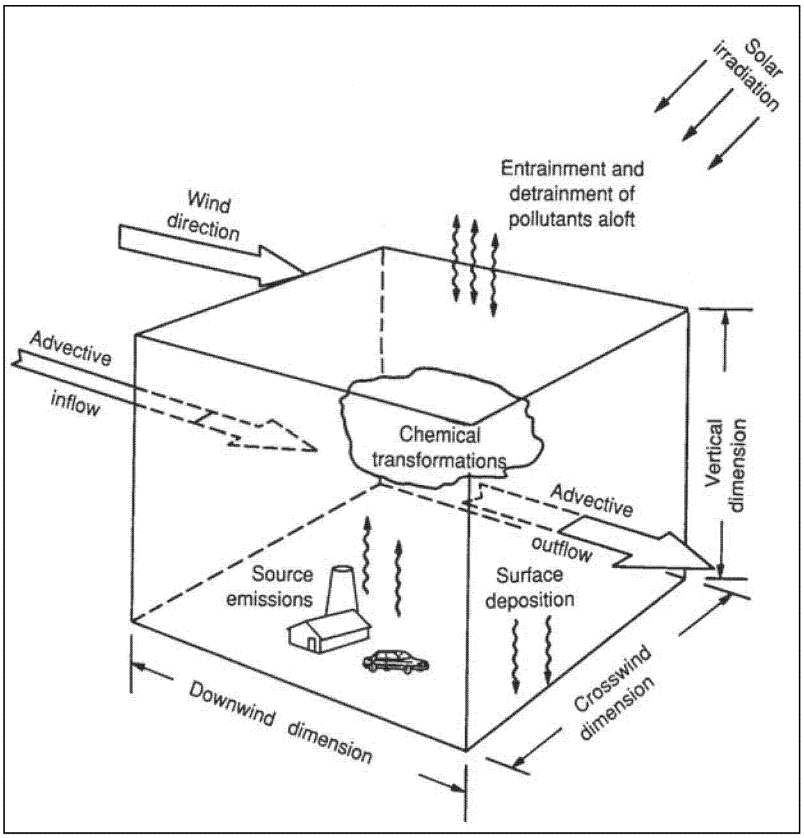

Figure 9. Overview of processes treated in a single grid cell of an Eulerian photochemical model.

15. The CAMx modeling system simulates various chemical and physical processes that are important for understanding atmospheric trace gas transformations and distributions and contains three types of modeling components: (1) a meteorological modeling system for the description of atmospheric states and motions; (2) emission models for characterizing man-made and natural emissions that are injected into the atmosphere; and (3) a chemistry-transport modeling system for simulating the chemical transformation and fate of air pollutants. In addition, the CAMx modeling system includes particulate matter source apportionment technology (PSAT), a source apportionment tool that can be used to estimate the contributions of individual sources or groups of sources to PM concentrations at selected receptor locations. Chemical

transport models, such as CAMx, mix emissions from different sources together. A source apportionment approach can be used to estimate the contributions of individual sources or groups of sources to PM concentrations at selected receptor locations. PSAT is a source apportionment tool developed for CAMx to track the formation and transport of $PM_{2.5}$ from emissions source categories (e.g., mobile, point, biogenic, etc.) and geographic source regions. PSAT can track source contributions to sulfate, nitrate, ammonium, secondary organic aerosol (SOA), and several primary PM species (e.g., elemental carbon, primary organic aerosol, and crustal PM). PSAT has been tested for primary PM species, as well as secondary sulfate and nitrate PM species and can be useful for understanding model performance, designing PM emission control strategies, and performing culpability assessments to identify sources that contribute significantly to PM pollution (ENVIRON International Corporation, 2008).

16. To demonstrate the quantified impacts of the excess emissions, we used results from a CAMx PSAT modeling run performed by the U.S. EPA in support of the 24-hour $PM_{2.5}$ NAAQS designation process (Baker and Timin, 2008). These are the same modeling results that I relied upon to reach conclusions about the impacts of the Wabash River Power Plant in a previous case (United States of America, et al. v. Cinergy Corp., et al. C.A. No. IP99-1693 C-M/S). EPA applied CAMx version 4.5 with full gas-phase and aerosol chemistry for the entire year of 2005, using a national 36 km resolution domain to supply boundary conditions to three nested 12 km resolution regional modeling domains. (Domain refers to the geographic area that is modeled.) PSAT results from the regional domain shown in **Figure 10** were used in this evaluation. These CAMx PSAT source apportionment results quantified impacts on $PM_{2.5}$ concentrations from

facilities which were among the top 5% of all stationary point sources of NO_x, SO_x, or primary $PM_{2.5}$ in the eastern half of the U.S., including the Monroe power plant. To estimate the impact of excess emissions from Unit 2 of the Monroe plant, the overall PSAT results for Monroe were scaled by multiplying the PSAT impacts from the Monroe power plant by the ratio of 2009 excess emissions to the total emissions from the Monroe power plant in the year modeled (2005). This scaling approach was applied to PSAT impacts associated with sulfate, elemental carbon, and crustal PM, which would be impacted by the 95% SO_2 reduction resulting from controls, and nitrate, which would be impacted by the 90% NO_x reduction resulting from controls. This approach assumes a linear relationship between primary precursor emissions and secondary $PM_{2.5}$ production, a generally accepted assumption in the air quality modeling community. It should also be noted that EPA evaluated model performance for the 2005 base case used in CAMx PSAT runs by comparing model estimates to observations of chemically speciated $PM_{2.5}$ collected at ambient monitoring sites during 2005. Metrics used to evaluate model performance include mean bias, gross error, fractional bias, and fractional error. For the Midwestern domain that is of interest to this study, model results for sulfate were found to be acceptable by EPA (Baker and Timin, 2008).

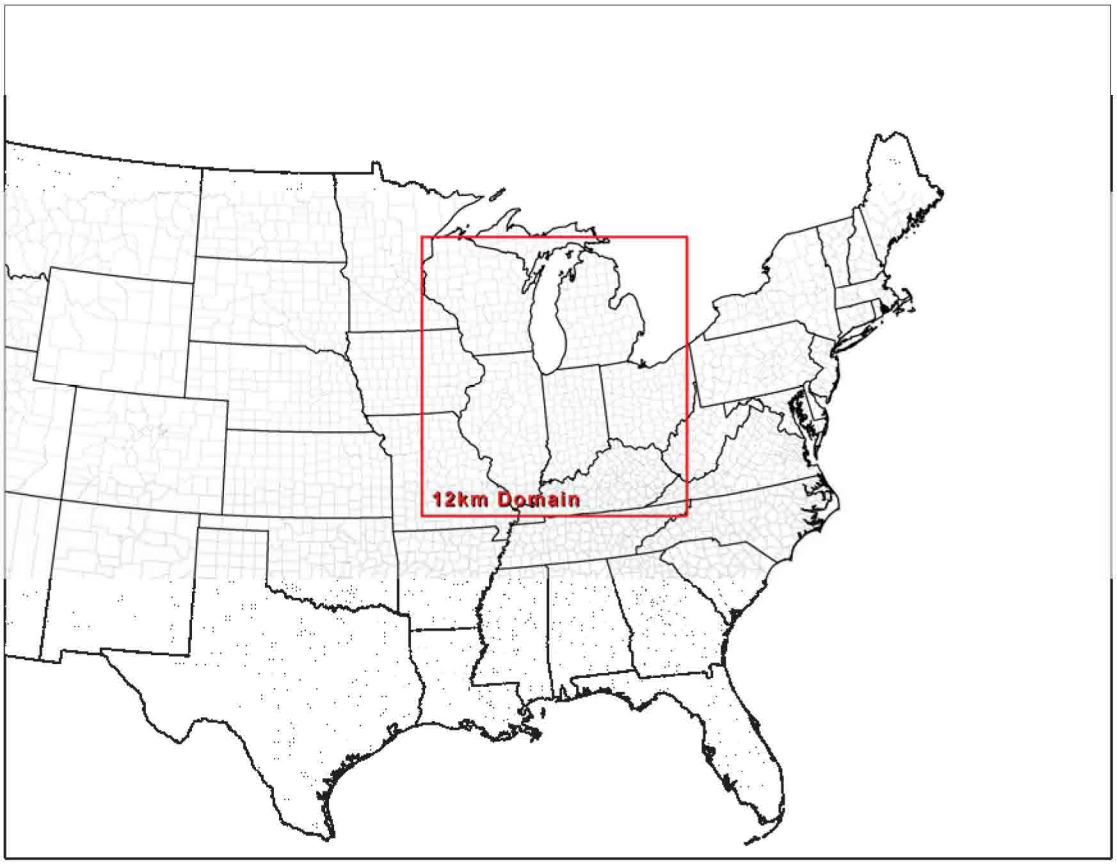

Figure 10. EPA modeling domain used for CAMx PSAT modeling.

17. Though the CAMX PSAT modeling performed by EPA was representative of 2005 meteorological conditions, an inspection of key meteorological parameters demonstrated that 2005 was not an unusual meteorological year. Several meteorological parameters are widely known in the air quality community to be good predictors of stagnation conditions that lead to poor air quality, including the temperature at 850 mb (about 5,000 feet above the ground) and the height of the 500 mb pressure surface. **Figures 11 and 12** show monthly 850 mb temperatures and 500 mb geopotential heights for 1948 to 2008 derived from data from the NOAA-CIRES Climate Diagnostic Center reanalysis project (NOAA-CIRES Climate Diagnostic Center, 2003), which uses a state-of-the-art analysis/forecast system to perform data assimilation using past data from 1948 to

the present. The vertical blue line on these plots delineates the year 2005, and an inspection of these time series plots demonstrates that 2005 was not an unusual meteorological year and that our air quality analyses are representative of other historical years and will likely be representative of future years as well.

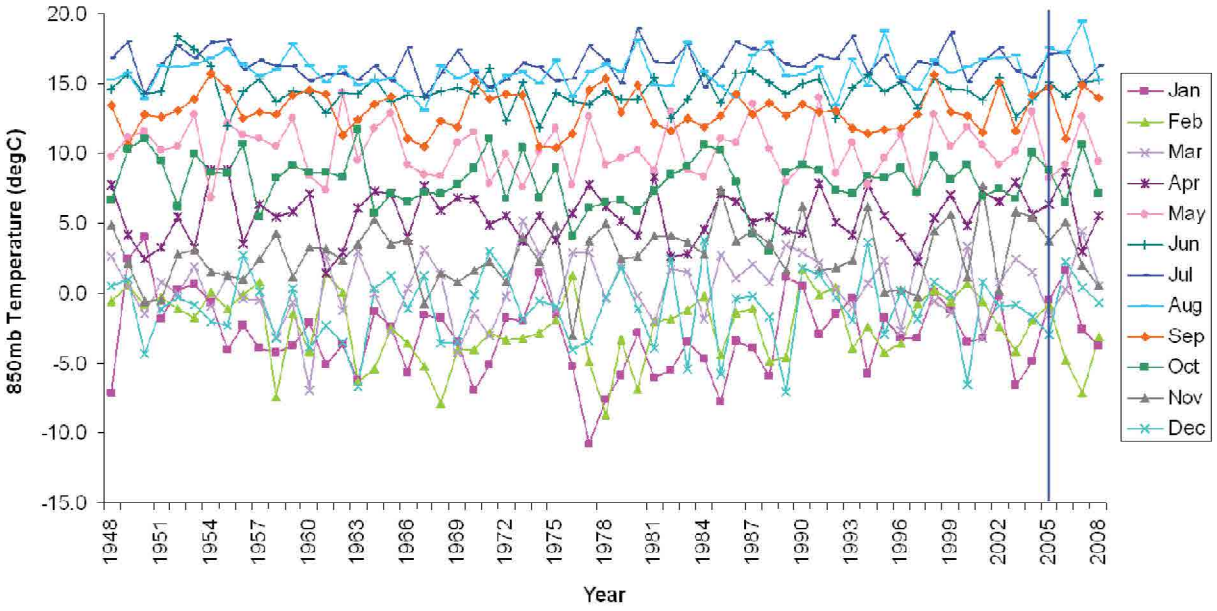

Figure 11. 850-mb temperatures (°C) by month over the Midwest and Northeast United States from 1948 to 2008. The vertical blue line delineates the year 2005.

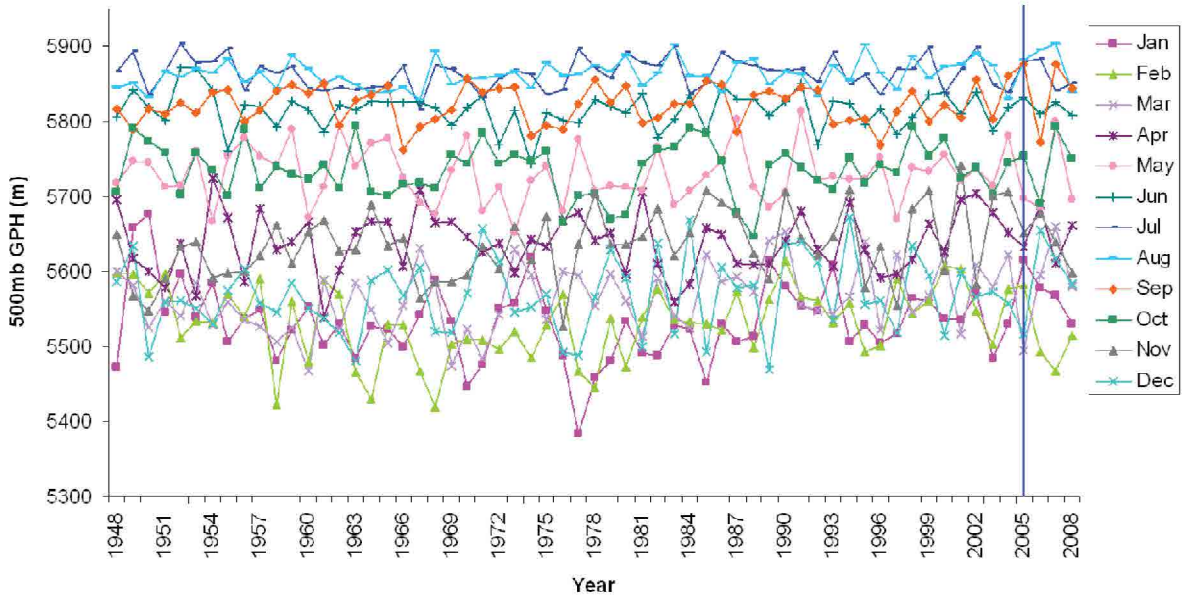

Figure 12. 500-mb geopotential heights (m) by month over the Midwest and Northeast United States from 1948 to 2008. The vertical blue line delineates the year 2005.

18. CAMx PSAT modeling results show that excess emissions from Unit 2 of the Monroe power plant have an impact of at least 0.5 $\mu g/m^3$ on $PM_{2.5}$ concentrations in the Detroit-Ann Arbor non-attainment area on 23 days in 2005, with impacts as high as 1.5 $\mu g/m^3$ occurring on July 28 and August 17. In addition, excess emissions from Monroe Unit 2 have impacts as high as 0.9 $\mu g/m^3$ in the Cleveland-Akron-Lorain non-attainment area in 2005, and as high as 0.3 $\mu g/m^3$ in Milwaukee-Racine non-attainment area (see **Table 2**). To illustrate the $PM_{2.5}$ air quality impacts of the excess SO_2 emissions from the Monroe power plant, **Figure 13** provides sample CAMx-PSAT modeling results for August 17, 2005. The CAMx model provides an estimate of how the excess SO_2 emissions impacted $PM_{2.5}$ pollution levels on that day. As shown in the figure, the impacts from the excess emissions from the Monroe power plant on $PM_{2.5}$ concentrations are greatest in Monroe County, Michigan, reaching about 1.5 $\mu g/m^3$ on August 17. In

addition, impacts from the Monroe power plant's excess emissions exceed 0.5 $\mu g/m^3$ across a large area that includes southeastern Michigan and northern parts of Ohio and Indiana, and the zone of impacts in excess of 0.25 $\mu g/m^3$ extends beyond Michigan, Indiana, and Ohio to cross the central part of Illinois. On an annual basis, the impacts from the Monroe plant's excess emissions on $PM_{2.5}$ concentrations are greatest in Monroe County, reaching 0.1 $\mu g/m^3$ (see **Figure 14**). Because of the law of conservation of mass, excess emissions from Monroe Unit 2 cannot be destroyed but only shifted in space or transformed; therefore, these emissions impact the air quality in some location every day of the year. To demonstrate this fact, the CAMx PSAT modeling results for every day of 2005 are provided in the DVD attached as Appendix F to this declaration.

Non-attainment area	Maximum impact on 24-hr $PM_{2.5}$ concentrations ($\mu g/m^3$)	Date(s) of maximum impact on 24-hour $PM_{2.5}$ concentrations
Detroit-Ann Arbor, MI	1.5	July 28 and August 17
Cleveland-Akron-Lorain, OH	0.9	February 4
Milwaukee-Racine, WI	0.3	July 12

Table 2. Peak modeled impacts on year-2005 $PM_{2.5}$ concentrations from excess emissions from Unit 2 of the Monroe power plant.

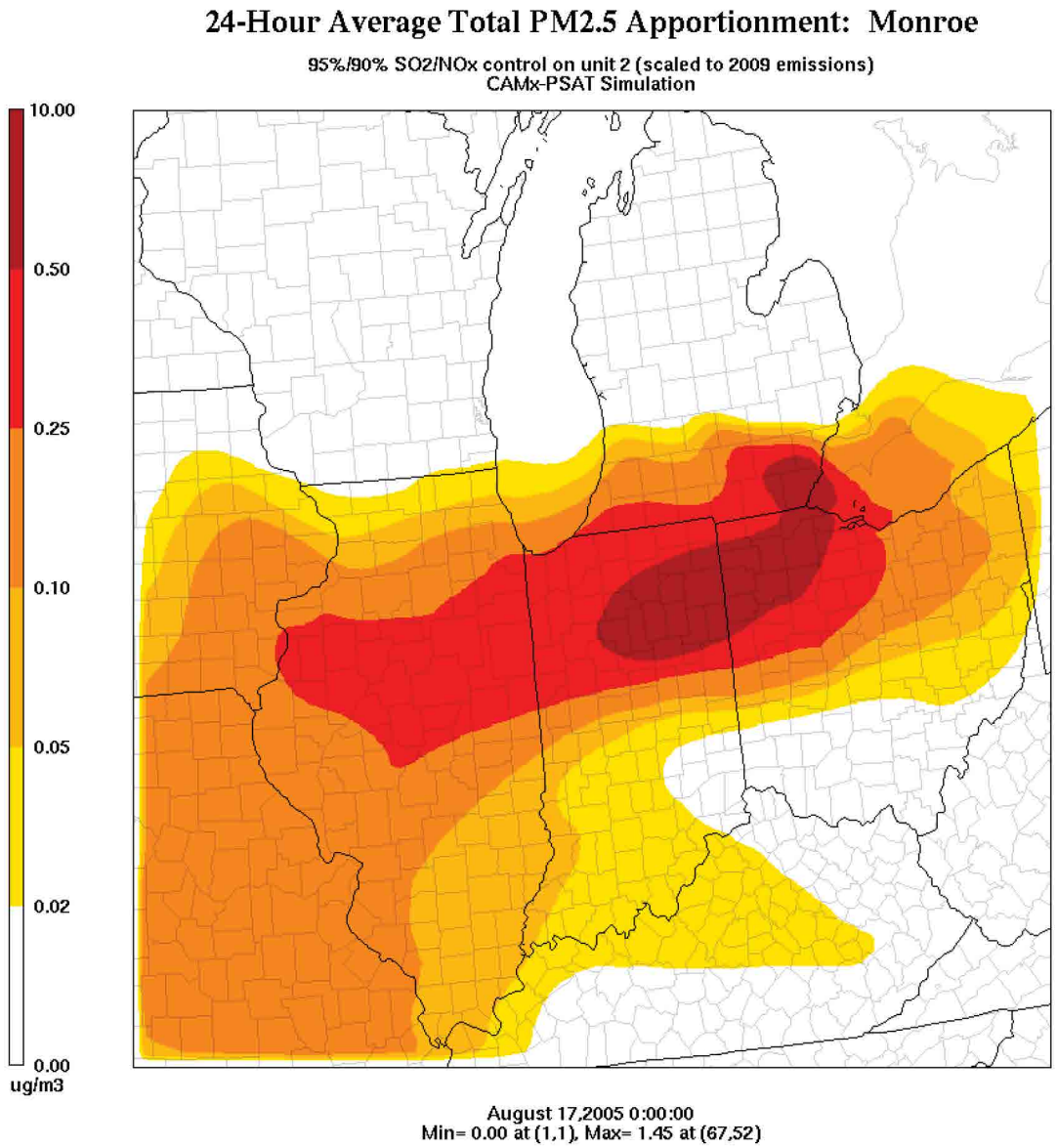

Figure 13 . CAMx-predicted impact on 24-hour average $PM_{2.5}$ concentrations for August 17, 2005 from the current excess emissions at the Monroe power plant.

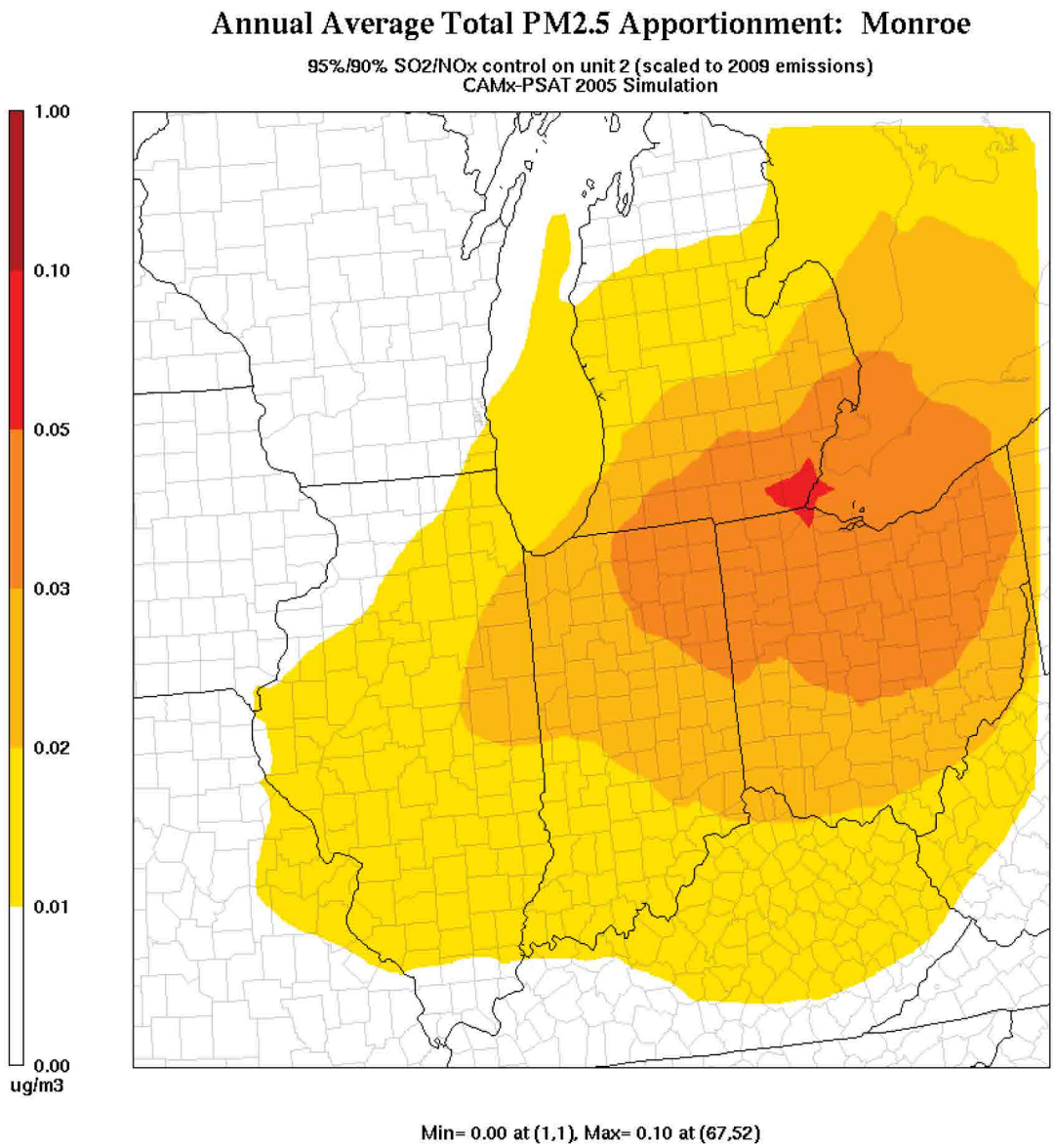

Figure 14. CAMx-predicted impact on annual average $PM_{2.5}$ concentrations from excess emissions at the Monroe power plant.

19. To put these impacts in perspective, the current 24-hr $PM_{2.5}$ design value[2] for Detroit-Ann Arbor $PM_{2.5}$ nonattainment area is 37 $\mu g/m^3$, which means that this area is only exceeding the 24-hr standard by 2 $\mu g/m^3$. Similarly, the current annual $PM_{2.5}$ design

[2] Design values are calculated from measured pollutant concentrations in an area and quantify the area's air quality relative to the national standard (see http://www.epa.gov/air/airtrends/values.html). For $PM_{2.5}$, the annual standard is 15 $\mu g/m^3$.

value for Detroit-Ann Arbor $PM_{2.5}$ nonattainment area is 15.4 $\mu g/m^3$, a value which only exceeds the annual standard by 0.4 $\mu g/m^3$. As a result, reductions in $PM_{2.5}$ concentrations of tenths of a $\mu g/m^3$ are substantial from an air quality planning perspective, as such reductions could dramatically affect the attainment status of an area such as Detroit-Ann Arbor, in addition to the incremental health benefits associated with such decreases in $PM_{2.5}$ concentrations. This opinion is similar to conclusions reached during previous CAMx PSAT modeling used to investigate the contribution of power plant SO_2 emissions to particulate sulfate concentrations in the eastern U.S. In that peer-reviewed study, Wagstrom et al (2008) found that SO_2 emissions from power plants significantly impacted areas as far as 500 km from the source region and concluded that impacts of several tenths of a $\mu g/m^3$ are significant.

20. Excess emissions and $PM_{2.5}$ impacts from Monroe Unit 2 are comparable to emissions levels and $PM_{2.5}$ impacts from entire power plants in the Detroit Edison generating fleet in Michigan. Like the Monroe power plant, Detroit Edison's Belle River, St. Clair, River Rouge, and Trenton Channel plants are all in the Detroit area of southeastern Michigan, as shown in **Figure 15**. Excess SO_2 emissions from Monroe Unit 2 are within about ±10% of 2009 SO_2 emissions from the Belle River, St. Clair, and Trenton Channel plants and are 42% higher than 2009 SO_2 emissions from the River Rouge plant (see **Figure 16**). As a result, impacts on regional $PM_{2.5}$ concentrations from excess emissions from Monroe Unit 2 are likely to be similar to impacts from the Belle River, St. Clair, and Trenton Channel facilities. For example, CAMx PSAT-derived impacts on annual $PM_{2.5}$ concentrations from the Trenton Channel power plant, which is

about 18 miles northeast of the Monroe plant, show a similar maximum and spatial distribution as impacts from excess emissions from Monroe Unit 2 (see **Figure 17**).

Figure 15. Locations of Detroit Edison power plants in southeastern Michigan.

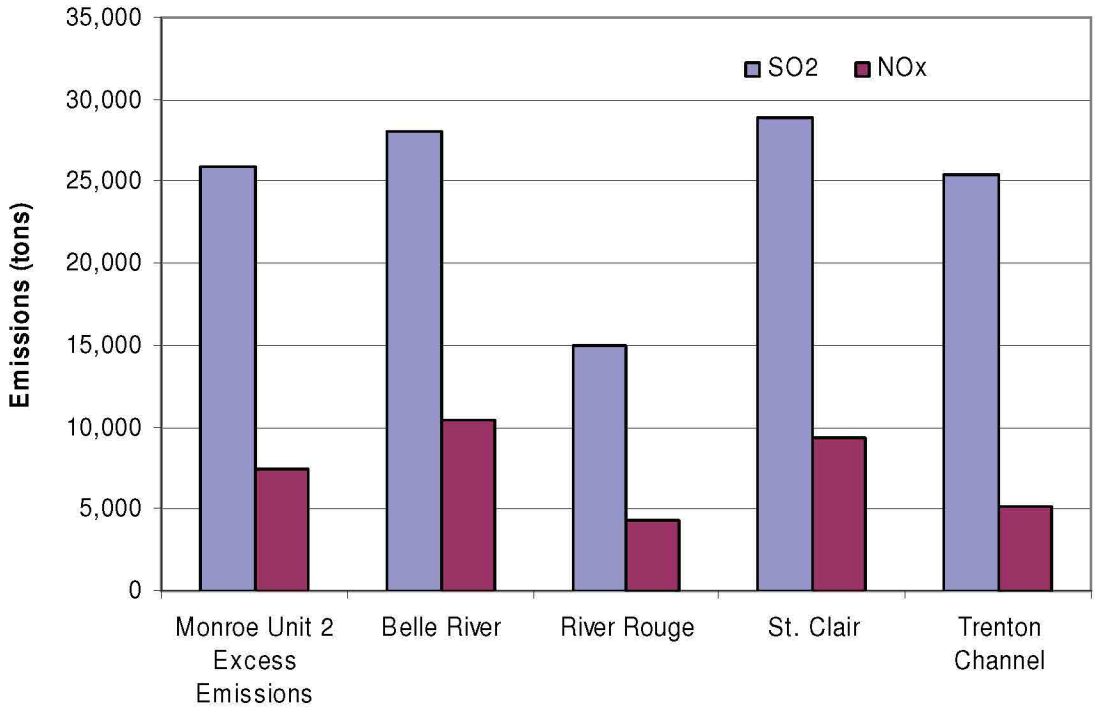

Figure 16. Comparison of excess emissions from Unit 2 of the Monroe power plant to 2009 emissions from other Detroit Edison power plants in Michigan.

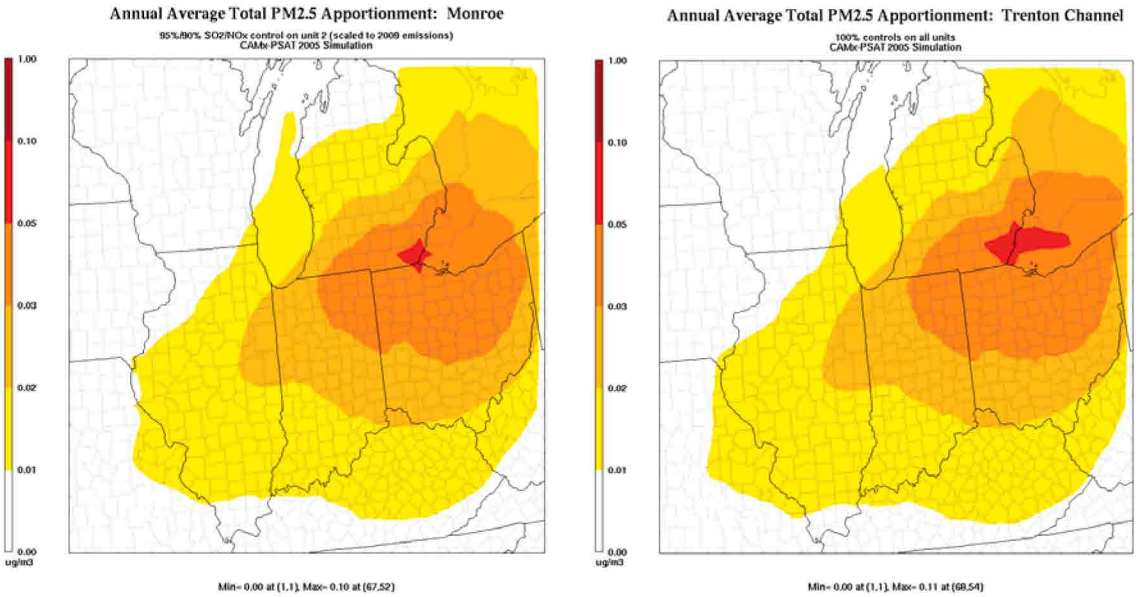

Figure 17. Comparison of CAMx-predicted annual average $PM_{2.5}$ impacts from excess emissions at the Monroe power plant and 2009 emissions from Detroit Edison's Trenton Channel plant.

21. In this region sulfate has been shown to be a greater contributor to $PM_{2.5}$ concentrations than nitrate. Therefore, controlling SO_2 emissions provides greater reductions in $PM_{2.5}$ concentrations in this region than controlling NO_x emissions. It follows that additional SO_2 emission controls could be used instead of NO_x emission controls to achieve the same or greater $PM_{2.5}$ air quality benefits.

22. In addition to the impacts on $PM_{2.5}$ concentrations in areas within EPA's CAMx PSAT modeling domain, excess emissions from Unit 2 of the Monroe plant are likely to impact $PM_{2.5}$ concentrations beyond the boundaries of the modeling domain as well. Under certain conditions, SO_2 may only convert to sulfate at a rate of 1% per hour, which allows the SO_2 to be transported for several days before conversion. Because of such pollutant transport, EPA has encouraged states to address air quality issues such as visibility impairment from a regional perspective, providing funding to five regional planning organizations (RPOs) that address regional haze and related issues across broad geographic areas.

23. Though EPA's CAMx PSAT modeling was focused on quantifying source contributions to $PM_{2.5}$ concentrations, excess NO_x emissions from Monroe Unit 2 would also impact regional ozone concentrations. Ground-level ozone is a secondary pollutant formed through the photochemical reactions of NO_x, VOC, and sunlight, and like $PM_{2.5}$, ozone can be transported over thousands of kilometers. Previous modeling studies have demonstrated the effectiveness of power plant NO_x controls in decreasing peak 8-hr ozone concentrations in the upper Midwest, including a previous modeling analysis that I performed with the Community Multiscale Air Quality model (CMAQ)[3] to investigate

[3] CMAQ is another state-of-the-science, peer-reviewed air quality model.

the impact of excess NO_x emissions at the Wabash River power plant in western Indiana (CIVIL ACTION NO. IP99-1693 C-M/S).

24. In conclusion, the excess emissions from the Monroe power plant are currently having a negative impact on the air quality in nearby Detroit, throughout Michigan, in neighboring states, and in other states in the mid-eastern and eastern United States. Several of the areas impacted by the Monroe power plant are not in attainment of the NAAQS, meaning that the excess emissions are adding to areas that already have unhealthy air quality levels. These areas include Detroit-Ann Arbor, Michigan, Cleveland-Akron-Lorain, Ohio, and Milwaukee-Racine, Wisconsin.

25. This declaration does not represent the full extent of my opinions, which may be included in my future expert report(s).

I declare under penalty of perjury that the foregoing is true and correct.

Executed on August 3, 2010, at Petaluma, California

Lyle R. Chinkin

REFERENCES CITED

The following references were cited in the body of this declaration. All other data and information considering in forming the expressed opinions are listed in Appendix E.

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APPENDIX A

Lyle R. Chinkin Resume

RESUME
LYLE R. CHINKIN
President

Sonoma Technology, Inc.

1455 N. McDowell Blvd., Suite D
Petaluma, CA 94954-6503
707/665-9900
Fax: 707/665-9800
www.sonomatech.com

Educational Background

B.S. Atmospheric Science, *summa cum laude*, University of California at Davis, 1981
M.S. Atmospheric Science, University of California at Davis, 1984

Professional Experience

Mr. Chinkin joined Sonoma Technology, Inc. (STI) in 1992 and is STI's President. He has over 20 years of professional consulting experience in air quality and over 5 years of experience at the California Air Resources Board.

Mr. Chinkin is a nationally recognized expert in emission inventory preparation and assessment and air quality analysis. He has worked on projects for federal, state, and local government agencies; universities; public and private research consortiums; and major corporations. Mr. Chinkin's areas of expertise include (1) developing and improving regional emission inventories; (2) providing independent assessments of emission inventories using bottom-up and top-down evaluation techniques; (3) conducting field studies to obtain real-world data and improve activity estimates and emission factors; (4) conducting scoping studies to develop conceptual models of community-scale air quality; (5) assisting with State Implementation Plan (SIP) development; and (6) providing expert testimony and presentations to public boards. He has been appointed to the National Research Council of the National Academy of Sciences Committee on the Effects of Changes in New Source Review Programs for Stationary Sources of Air Pollutants and to a panel to review "Improving Emission Inventories for Effective Air Quality Management Across North America, a NARSTO Assessment".

Mr. Chinkin served as (1) an EPA-invited peer-reviewer of the EPA particulate matter (PM) National Ambient Air Quality Standards Criteria Document and the draft EPA Report on the Environment (ROE) 2006; (2) an expert panel member for the review of the Valdez Air Health Study; and (3) an expert witness for U.S. Department of Justice environmental enforcement actions. Mr. Chinkin was the project manager and co-author of the EPA national guidance document on the preparation of emission inputs for photochemical air quality simulation models. In addition, his projects have included improving estimates of PM and ammonia emissions, evaluating internal combustion engine activity profiles and emissions, determining emissions from propane use and distribution systems, determining air toxic emissions from wood-preservation activities, and improving biogenic emission estimation tools. He frequently directs studies that combine public- and private-sector participation (e.g., an assessment and ground-truth study of industrial emissions in the Houston Ship Channel under the joint direction of the Texas Natural Resource Conservation Commission [now Texas Commission on Environmental Quality] and local industry). Mr. Chinkin has also assisted numerous industrial clients with projects such as development of emission-estimation tools for the American Petroleum Institute and top-down evaluations of emission inventories for the Coordinating Research Council.

Mr. Chinkin is frequently called upon by clients to explain complicated technical information to other air quality professionals, advisory boards, and members of the public. He presented research findings to public advisory committees in Ohio, Kansas, and Missouri and to senior federal and state government officials in Minnesota and at numerous scientific conferences. EPA selected Mr. Chinkin to help prepare a summary of the proceedings of the 2003 NARSTO air quality research conference, and to help an audience of air quality officials from four western U.S. states understand technical air toxics assessment techniques.

Chronology of Education and Work Experience

- 1978 – 1979: Assistant Weather Producer, KCRA-TV Channel 3, Sacramento, CA
  - Decoded weather data and prepared in-studio weather displays for broadcast
- 1979 – 1981: Student Assistant, Meteorology Section, California Air Resources Board
  - Evaluated meteorological data
  - Analyzed isobaric pressure charts and wind flow patterns
- 1980: Weather Reporter, KDVS Radio Station, Davis, CA
  - Prepared and presented weather broadcasts for California
- 1980: Instrument Technician, Air Quality Group, University of California, Davis
  - Maintained and calibrated particulate samplers in remote areas of the western U.S.
- 1981: B.S. Atmospheric Science, *summa cum laude*, University of California at Davis
- 1981 – 1982: Air Pollution Specialist, Analysis and Projects Section, California Air Resources Board
  - Prepared comprehensive technical reports requiring computer programming and statistical analyses
  - Produced the "California Air Quality Data Report"
- 1982 – 1984: Assistant Meteorologist, Meteorology Section, California Air Resources Board
  - Conducted climatological studies relating to air pollution in California
  - Applied meteorological principles to engineering evaluations and statistical analyses
  - Developed guidelines for agricultural burning
- 1984: M.S. Atmospheric Science, University of California at Davis
- 1984 – 1989: Senior Atmospheric Scientist, Systems Applications, Inc., San Rafael, CA
  - Conducted emission inventory studies relating to air pollution in various regions of the U.S.
  - Developed software to process emission inventory data into model-ready inputs for comprehensive 3-dimensional photochemical models
- 1989 – 1992: Manager of Emissions Modeling Group, Systems Applications, Inc., San Rafael, CA
  - Managed emission inventory studies relating to air pollution throughout the U.S. and Asia
  - Conducted air quality studies for government and private industry
- 1992 – 1998: Manager of Emissions Modeling, Sonoma Technology, Inc., Petaluma, CA

  - Managed emission inventory studies relating to air pollution worldwide
  - Managed air quality studies for government and private industry
  - Managed a multi-million dollar level-of-effort contract with the U.S. Environmental Protection Agency for air quality modeling assistance
- 1998: Vice President, Sonoma Technology, Inc., Petaluma, CA
  - Managed emissions modeling group and meteorological programs group
- 1999: Vice President and General Manager, Sonoma Technology, Inc., Petaluma, CA
  - Managed emissions modeling group and meteorological programs group
  - Responsible for financial oversight of company operations including financial performance (e.g., cash flow, profit and loss, backlog and overhead rates)
- 2000: Appointed to the Board of Directors, Sonoma Technology, Inc., Petaluma, CA
- 2002: Senior Vice-President, Sonoma Technology, Inc., Petaluma, CA
- 2004: Appointed to the National Research Council of the National Academy of Sciences Committee on the Effects of Changes in New Source Review Programs for Stationary Sources of Air Pollutants
- 2005: Selected as peer-reviewer for NARSTO report "Improving Emission Inventories for Effective Air Quality Management Across North America"
- 2006 – Present: President, Sonoma Technology, Inc., Petaluma, CA

Professional Memberships

Air & Waste Management Association
American Meteorological Society (1979-1984)
California Registered Environmental Assessor (REA-00715) (1984–1989)

Professional Development

1982: Statistics for Decision Makers
1982: Air Pollution Enforcement Symposium, California Air Resources Board
2001: Understanding Finance and Accounting

Peer Reviewer

U.S. Environmental Protection Agency
Journal of the Air and Waste Management Association
North American Research Strategy for Tropospheric Ozone (NARSTO)

APPENDIX B

LIST OF PUBLICATIONS

This appendix contains the lists of publications for Lyle R. Chinkin.

LYLE R. CHINKIN

Journal Articles

McCarthy M.C., Hafner H.R., Chinkin L.R., and Charrier J.G. (2007) Temporal variability of selected air toxics in the United States. Atmos. Environ., doi:10.1016/j.atmosenv.2007.1005.1037 (STI-2894).

McCarthy M.C., Eisinger D.S., Hafner H.R., Chinkin L.R., Roberts P.T., Black K.N., Clark N.N., McMurry P.H., and Winer A.M. (2006) Particulate matter: a strategic vision for transportation-related research (submitted). (STI-904750-2843).

Chinkin L.R., Coe D.L., Funk T.H., Hafner H.R., Roberts P.T., Ryan P.A., and Lawson D.R. (2003) Weekday versus weekend emissions activity patterns for ozone precursor emissions in California's South Coast Air Basin. *J. Air & Waste Manag. Assoc.* **53**, pp. 829-843 (STI-999679-2225).

Funk T.H., Chinkin L.R., Roberts P.T., Saeger M., Mulligan S., Figeroa V.H.P., and Yarbrough J. (2001) Compilation and evaluation of a Paso del Norte emission inventory. *Sci. Total Environ.* (Special Issue: U.S.-Mexico Transboundary Air Pollution Studies) **276, Nos. 1-3**, 135-151 (STI-1942).

Magliano K.L., Hughes V.M., Chinkin L.R., Coe D.L., Haste T.L., Kumar N., and Lurmann F.W. (1999) Spatial and temporal variations in PM_{10} and $PM_{2.5}$ source contributions and comparison to emissions during the 1995 Integrated Monitoring Study. *Atmos. Environ.* **33**, 4757-4774.

Chinkin L.R., Chang D.P.Y., and Floccini R.G. (1986) Relationships among the coefficient of haze, scattering coefficient, and visibility during an agricultural burn season. *J. Air Pollut. Control Assoc.* **36**, 173-178.

Meeting Presentations and Conference Proceedings

Raffuse S., Gilliland E., Sullivan D., Wheeler N., Chinkin L., Larkin S., Solomon R., Strand T., and Pace T. (2008) Development of wildland fire emission inventories with the BlueSky Smoke Modeling Framework. Presented at the 7th Annual Community Modeling and Analysis System (CMAS) Conference Chapel Hill, NC, October 7, by Sonoma Technology, Inc., Petaluma, CA; U.S. Forest Service AirFIRE Team, Seattle, WA; and U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC (STI-3457).

Larkin N.K., Strand T., Solomon R., Raffuse S., Sullivan D.C., Chinkin L., Brown T., O'Neill S., Friedl L., and Knighton R. (2008) The state of smoke tools: What we know now. Presented at the International Association of Wildland Fire, The '88 Fires: Yellowstone & Beyond, Jackson Hole, WY, September 22-27, by the U.S. Forest Service AirFire Team, Seattle, WA; Sonoma Technology, Inc., Petaluma, CA; Desert Research Institute, Reno, NV; USDA Natural Resource Conservation Service, Portland, OR; NASA, Washington, D.C.; and USDA Cooperative State Research, Education, and Extension Service, Washington, D.C.

Raffuse S.M., Sullivan D.C., Gilliland E.K., Chinkin L.R., Larkin S., Solomon R., and Pace T. (2008) Development of wildland fire emission inventories for 2003-2006 and sensitivity analyses. Presentation made at the U.S. Environmental Protection Agency's 17th International Emission Inventory Conference, Portland, OR,, June 5, by Sonoma Technology, Inc., Petaluma, CA; U.S. Forest Service AirFire Team, Seattle, WA; and U.S. Environmental Protection Agency Office of Air Quality Planning and Standards, Research Triangle Park, NC (STI-905028-3377).

Sullivan D.C., Raffuse S.M., Pryden D.A., Craig K.J., Reid S.B., Wheeler N.J.M., Chinkin L.R., Larkin N.K., Solomon R., and Strand T. (2008) Development and applications of systems for modeling emissions and smoke from fires: the BlueSky smoke modeling framework and SMARTFIRE. Paper presented at the 17th International Emissions Inventory Conference, Portland, OR, June 5, by Sonoma Technology, Inc., Petaluma, CA, and the U.S. Forest Service, Seattle, WA (STI-3378).

Wheeler N.J.M., Craig K.J., Reid S.B., Gilliland E.K., Sullivan D.C., and Chinkin L.R. (2008) The BlueSky Gateway air quality forecast system for fire management. Presented at the BlueSky Smoke Modeling Framework Stakeholders' Meeting, Boise, ID, May 20-22 (STI-905028-3367).

Raffuse S.M., Sullivan D.C., Chinkin L.R., Pryden D.A., Wheeler N.J.M., Larkin N.K., Solomon R., and Soja A. (2007) Integration and reconciliation of satellite-detected and incident command-reported wildfire information in the BlueSky smoke modeling framework. Presented at the 6th Annual CMAS Conference, Chapel Hill, NC, October 1-3, by Sonoma Technology, Inc., Petaluma, CA, the U.S. Forest Service AirFire Team, Seattle, WA, and the National Institute of Aerospace, Hampton, VA (STI-3227).

Raffuse S.M., Sullivan D.C., Chinkin L.R., Larkin N.K., Solomon R., and Soja A. (2007) Integration of satellite-detected and incident command-reported wildfire information into BlueSky. Paper No. 205 presented at the Air & Waste Management Association's 100th Annual Conference & Exhibition, Pittsburgh, PA, June 26-29 (STI-3127).

Reid S.B., Chinkin L.R., Penfold B.M., and Gilliland E.K. (2007) Emissions inventory validation and improvement: a Central California case study. Conference paper prepared for the U.S. Environmental Protection Agency's 16th Annual Emission Inventory Conference, Raleigh, NC, May 14-17, by Sonoma Technology, Inc., Petaluma, CA (STI-3109).

Raffuse S.M., Sullivan D.C., Chinkin L.R., Larkin S., Solomon R., and Soja A. (2007) Integration of satellite detected and incident command reported wildfire information into BlueSky. Presented at the BlueSky Annual Meeting, Winthrop, WA, May 22, by Sonoma Technology, Inc., Petaluma, CA, U.S. Forest Service AirFire Team, Seattle, WA, and the National Institute of Aerospace, Hampton, VA (STI-3086).

Chinkin L. and Reid S. (2006) Improvements to the spatial and temporal representativeness of modeling emission estimates. Presentation to the CCOS Technical Committee, Sacramento, CA, STI-906036.01-2995, July 6.

Reid S.B., Brown S.G., McCarthy M.C., and Chinkin L.R. (2006) Comparison of ambient measurements to emissions representations for modeling in California's San Joaquin Valley. Presented to the *U.S. Environmental Protection Agency's 15th Annual Emission Inventory Conference, New Orleans, LA, May 18*, by Sonoma Technology, Inc., Petaluma, CA (STI-2944).

Raffuse S.M., Sullivan D.C., Chinkin L.R., Larkin S., and Solomon R. (2006) Expanding BlueSkyRAINS to support emission inventory preparation. Presented at the *U.S. Environmental Protection Agency's 15th Annual Emission Inventory Conference, New Orleans, LA, May 17*, by Sonoma Technology, Inc., Petaluma, CA, and U.S. Department of Agriculture, Forest Service, Seattle, WA (STI-2950).

Hafner H.R., McCarthy M.C., and Chinkin L.R. (2006) National, regional, between-city, and within-city spatial variability in air toxics. Presented at the *AWMA Symposium on Air Quality Measurement Methods and Technology, Durham, NC, May 9*, by Sonoma Technology, Inc., Petaluma, CA (STI-2884).

Hafner H.R., McCarthy M.C., and Chinkin L.R. (2006) Temporal trends in air toxics. Presented at the *AWMA Symposium on Air Quality Measurement Methods and Technology, Durham, NC, May 9*, by Sonoma Technology, Inc., Petaluma, CA (STI-2885).

Chinkin L.R. (2005) Comparison of ambient measurements to emissions representations in modeling. Presentation at the California Air Resources Board, CCOS Technical Committee, Sacramento, CA, by Sonoma Technology, Inc., Petaluma, CA, STI-905044-2838, October.

Hafner H.R., McCarthy M.C., and Chinkin L.R. (2005) National air toxics assessments: lessons learned in quantifying ambient air toxics temporal and spatial trends. Presented at the *2005 Air Toxics Summit, Seeking Solutions for our Rural and Urban Communities, Portland, OR, October 18-19* by Sonoma Technology, Inc., Petaluma, CA (STI-905102-2756).

McCarthy M.C., Hafner H.R., Chinkin L.R., Cozzo E.M., Raffuse S.M., and Gray E.A. (2005) Air toxics monitoring data analysis workshop. Presentation prepared for the U.S. Environmental Protection Agency, Raleigh, NC, by Sonoma Technology, Inc., Petaluma, CA, STI-905102-2799, September.

Wheeler N.J., Chinkin L.R., Reid S.B., Gross T., Hawkins A., Watson D., Vit W., Mefrakis R., and Joerke J. (2005) Regional photochemical modeling for the Kansas City Clean Air Action Plan: what it tells us about the challenges ahead for 8-hr ozone nonattainment areas. Presented at the *4th Annual CMAS Models-3 User's Conference, Chapel Hill, NC, September 26-28,* by Sonoma Technology, Inc., Petaluma, CA; Missouri Department of Natural Resources, Jefferson City, MO; Mid-America Regional Council, Kansas City, MO (STI-2800).

Raffuse S.M., Brown S.G., Sullivan D.C., and Chinkin L.R. (2005) Estimating regional contributions to atmospheric haze. Presented at the *2005 ESRI International User Conference, San Diego, CA, July 26* (STI-2649).

Raffuse S.M., Sullivan D.C., and Chinkin L.R. (2005) Emission impact potential - a method for relating upwind emissions to ambient pollutant concentrations. Presented at *the U.S. Environmental Protection Agency 14th International Emission Inventory Conference, Las Vegas, NV, April 11-14* by Sonoma Technology, Inc., Petaluma, CA (STI-2715, STI-2722).

Reid S.B., Sullivan D.C., Stiefer P.S., and Chinkin L.R. (2005) Development of emission inventories of recreational boats and commercial marine vessels for the Central States Regional Air Planning Association. Presented at *the U.S. Environmental Protection Agency 14th International Emission Inventory Conference, Las Vegas, NV, April 11-14* by Sonoma Technology, Inc., Petaluma, CA (STI-2714, STI-2721).

Sullivan D.C., Reid S.B., Penfold B.M., and Chinkin L.R. (2005) Development of agricultural dust emission inventories for the Central States Regional Air Planning Association. Presented at *the U.S. Environmental Protection Agency 14th International Emission Inventory Conference, Las Vegas, NV, April 11-14* by Sonoma Technology, Inc., Petaluma, CA (STI-2713, STI-2720).

Sullivan D.C., Reid S.B., Stiefer P.S., Funk T.H., and Chinkin L.R. (2005) On-road mobile source emission inventory development for the Central States Regional Air Planning Association. Presented at *the U.S. Environmental Protection Agency 14th International Emission Inventory Conference, Las Vegas, NV, April 11-14* by Sonoma Technology, Inc., Petaluma, CA (STI-2712, STI-2719).

Reid S.B., Funk T.H., Sullivan D.C., Stiefer P.S., Arkinson H.L., Brown S.G., and Chinkin L.R. (2004) Research and development of emission inventories for planned burning activities for the Central States Regional Air Planning Association. Paper for the *13th International Emission Inventory Conference "Working for Clean Air in Clearwater", Clearwater, FL, June 8-10* (STI-2515).

Wheeler N.J.M., Lurmann F.W., Hafner H.R., Chinkin L.R., Sullivan D.C., and Roberts P.T. (2004) Changing roles of oxides of nitrogen as precursors in photochemistry. Presentation at the *Annual Meeting of the West Coast Section, Air & Waste Management Association, Ventura, CA, May 13,* STI-2539.

Bahm K.E., Chinkin L.R., Sullivan D.C., and Broaders K.E. (2004) Task 4.3: detecting source activities and reconciling ambient measurement variations with field observations. Presented to *California Regional $PM_{10}/PM_{2.5}$ Air Quality Study (CRPAQS) Data Analysis Workshop, Sacramento, CA, March 9-10* by Sonoma Technology, Inc., Petaluma, CA (STI-902328-2501).

Coe D.L., Chinkin L.R., Reid S.B., and Stiefer P.S. (2003) Weekday-weekend emissions patterns for southern California: observations and implications. Presented at the *NARSTO Workshop on Innovative Methods for Emission-Inventory Development and Evaluation, University of Texas at Austin, October 14-17* (STI-2421).

Chinkin L.R., Coe D.L., Hafner H.R., and Tamura T.M. (2003) Air Toxics Emission Inventory Training Workshop. Sponsored by the U.S. Environmental Protection Agency, Region IX, Richmond, CA. Prepared by Sonoma Technology, Inc., Petaluma, CA, 903320-2398, July 15-16.

Coe D.L., Gorin C.A., Chinkin L.R., and Reid S.B. (2003) Observations of weekday-weekend activity patterns for area sources in the Los Angeles area. Paper and presentation prepared for and presented at the U.S. Environmental Protection Agency, *12th International Emission Inventory Conference "Emission Inventories - Applying New Technologies", San Diego, CA, April 28 - May 1* (STI-2278).

Coe D. L., Chinkin L.R., Stiefer, P.S., and Funk T.H. (2003) Observations of weekday-weekend activity patterns for on-road mobile sources in the Los Angeles area. Presented at the *13th Annual Coordinating Research Council (CRC) On-Road Vehicle Emissions Workshop, San Diego, CA, April 7-9, 2003* (STI-2277).

Chinkin L.R. and Ryan P.A. (2002) Recommended improvements to the CMU Ammonia Emission Inventory Model for use by LADCO. Paper prepared for and presented at the Midwest RPO Emissions Inventory Meeting, Des Plaines, IL, November 20, by Sonoma Technology, Inc., Petaluma, CA (STI-902350-2280).

Chinkin L.R., MacDonald C.P., Funk T.H., Crews J.M., Dye T.S., and Wheeler N.J.M. (2002) Preliminary assessment of ozone air quality in the Minneapolis/St. Paul region. Presented at the Minnesota Environmental Initiative Clean Air Minnesota Rollout, St. Paul, MN, October 30, STI-901104-901105-2242.

Coe D.L., Gorin C.A., and Chinkin L.R. (2002) Emission inventories of OCS production and development activities in the Gulf of Mexico. Presentation at U.S. Department of Interior, Minerals Management Service, New Orleans, LA, September (STI-998203-2262).

Wheeler N., Lurmann F., Chinkin L., LeBaron B., Barickman P., Eden J., and Cruickshank T. (2002) Wintertime particulate matter modeling issues in the western United States. Presented at *Coordinating Research Council (CRC) Toxics Modeling Conference, The Woodlands, TX, February 27* (STI-2159).

Chinkin L.R. and Coe D.L. (2002) ARB weekday and weekend emissions studies of the 2002 ozone season. Presented to the California Air Resources Board Weekend Effect Work Group Meeting, Sacramento, CA, February 20, STI-901150-2157.

Wheeler N.J.M., Lurmann F.W., Ryan P.A., Roney J.A., Roberts P.T., MacDonald C.P., Chinkin L.R., Coe D.L., Hanna S., Seaman N., Hunter G., and Scalfano D. (2001) The SO_2 and NO_2 Increment Analysis for the Breton National Wilderness Area. Presented for the Minerals Management Service and Scientific Review Board, New Orleans, LA, December 13, STI-901369-2135.

Coe D.L., Ryan P.A., Funk T.H., and Chinkin L.R. (2001) DOE/OHVT weekday-weekend study: emissions activity results. Presented at the Weekday/Weekend Effect Workgroup, California Air Resources Board, Sacramento, CA, by Sonoma Technology, Inc., Petaluma, CA, STI-999677-2124, October 23.

Funk T.H., Coe D.L., and Chinkin L.R. (2001) Weekday versus weekend mobile source emissions activity patterns in California's South Coast Air Basin. Paper presented at the *International Emission Inventory Conference, Denver, CO, April 30 to May 3* (STI-2065).

Funk T.H. and Chinkin L.R. (2001) Using GIS technology for emission inventory and air quality applications. Presented at the *SCOS97-NARSTO Data Analysis Conference, February 13-15*, STI-2059.

Funk T.H. and Chinkin L.R. (2001) Development of spatial allocation factors for the SCOS97 domain. Presented at the *SCOS97-NARSTO Data Analysis Conference, February 13-15* (STI-2053).

Roberts P.T., Funk T.H., MacDonald C.P., Main H.H., and Chinkin L.R. (2000) Weekday/weekend ozone observations in the South Coast Air Basin. Presented to California Air Resources Board, Sacramento, CA, by Sonoma Technology, Inc., Santa Rosa, CA, STI-999670-1966, April 13.

Funk T.H. and Chinkin L.R. (1999) The use of PAMS data to evaluate emission inventory estimates in California. Preprints in *Emission Inventory Regional Strategies for the Future, Raleigh, NC, October 26-28,* Air & Waste Management Association, Pittsburgh, PA (STI 1876).

Haste T.L., Kumar N., Chinkin L.R., Roberts P.T., Saeger M., Mulligan S., and Yarbrough J. (1999) Compilation and evaluation of a Paso del Norte emission inventory for use in photochemical dispersion modeling. Paper no. 99-190 presented at the *Air & Waste Management Association 92nd Annual Meeting & Exhibition, St. Louis, MO, June 20-24* (STI 1862).

Chinkin L.R., Haste T.L., Coe D.L., Puri A.K., Hall J.V., and Levy S. (1998) Emission inventory projection project. Presented at *Air & Waste Management Association's Emission Inventory: Living in a Global Environment, New Orleans, LA, December 8-10* (STI 1840).

Haste T.L., Kumar N., Chinkin L.R., Roberts P.T., Saeger M., Mulligan S., Figueroa V.H.P., and Yarbrough J. (1998) Compilation and evaluation of a Paso del Norte emission inventory for use in photochemical dispersion modeling. Presented at the *Air & Waste Management Association's Emission Inventory: Living in a Global Environment, New Orleans, LA, December 8-10* (STI 1839).

Wilkinson J.G., Chinkin L.R., Coe D.L., Fitz D., Loomis C.F., Magliano K., Pankratz D., Ringler E., Waldron T., and Zwicker J. (1998) A model to estimate temporally resolved ammonia emissions at a dairy. *91st Annual Air & Waste Management Association Meeting & Exhibition, San Diego, CA, June 14-18.*

Chinkin L.R., Main H.H., Reiss R., Roberts P.T., and Romonow S. (1998) Analysis of PAMS data to evaluate reformulated gasoline effects. Presented at the *8th Coordinating Research Council (CRC) On-Road Vehicle Emissions Workshop, San Diego, CA, April 20-23.*

Coe D.L. and Chinkin L.R. (1998) The use of a day-specific source activity database to augment CMB source apportionment modeling. Paper presented at the *Air & Waste Management Association $PM_{2.5}$ Conference, Long Beach, CA, January 28-30* (STI-1789).

Haste T.L., Chinkin L.R., Kumar N., Lurmann F.W., and Hurwitt S.B. (1998) Use of ambient data to evaluate a regional emission inventory for the San Joaquin Valley. Paper and presentation at *$PM_{2.5}$ A Fine Particle Standard, Long Beach, CA, sponsored by Air & Waste Management Association, the U.S. Environmental Protection Agency, and the U.S. Department of Energy, January 28-30* (STI-997211-1806, STI-997211-1794).

Richards L.W., Main H.H., Hurwitt S.B., and Chinkin L.R. (1998) 1995 Integrated Monitoring Study: comparison of light scattering measurements during winter months in the San Joaquin Valley. Presented at *$PM_{2.5}$ A Fine Particle Standard, Long Beach, CA, sponsored by Air & Waste Management Association, the U.S. Environmental Protection Agency, and the U.S. Department of Energy, January 28-30* (STI-997216-1803).

Main H.H., Roberts P.T., Reiss R., and Chinkin L.R. (1998) Analysis of PAMS data to evaluate reformulated gasoline effects. Paper prepared for presentation at the *Air and Waste Management Association 1998 Annual Meeting and Exhibition, San Diego, CA, June 14-18.*

Chinkin L. and Haste T.L. (1997) Use of PAMS data to evaluate an emission inventory test case: Southeast Texas. Paper presented at the *Air & Waste Management Association Emission Inventory: Planning for the Future Conference, Research Triangle Park, NC, October 28-30* (STI 1760).

Coe D., Chinkin L., Loomis C., Wilkinson J., Fitz J., and Pankratz D. (1997) Improvements to the ammonia emission inventory and demonstration of ammonia measurement techniques for California's San Joaquin Valley. Paper presented at the *Air & Waste Management Association Emission Inventory: Planning for the Future Conference, Research Triangle Park, NC, October 28-30* (STI 1761).

Chinkin L., Prouty J., Coe D., and Martino P.A. (1997) Development of an E&P emissions calculation tool. Paper No. SPE 37913 presented at the *1997 SPE/EPA Exploration and Production Environmental Conference, Dallas, TX, March 3-5* (STI-1707).

Reiss R. and Chinkin L. (1996) Ozone exceedance data analysis: representativeness of the 1995 summer ozone season in the Northeast. Paper presented at the *First NARSTO-Northeast Data Analysis Symposium and Workshop, Norfolk, VA, December 10-12*.

Chinkin L.R., Stoelting M.W., and Haste T. (1996) Development of a gridded leaf biomass inventory for use in estimating biogenic emissions for urban airshed modeling. Paper presented at the *Air & Waste Management Association Emission Inventory: Key to Planning, Permits, Compliance & Reporting Conference, New Orleans, LA, September 4-6* (STI-1596).

Coe D., Chinkin L., Reiss R., DiSogra C., and Hammerstrom K. (1996) An emission inventory of agricultural internal combustion engines for California's San Joaquin Valley. Paper presented at the *Air & Waste Management Association Emission Inventory: Key to Planning, Permits, Compliance & Reporting Conference, New Orleans, LA, September 4-6* (STI-1597).

Stoeckenius T.E., Roberts P.T., and Chinkin L.R. (1996) Development of an objective classification procedure for meteorological scenarios associated with high ozone concentrations in and around the San Francisco Bay area. Presented at the *Air & Waste Management Association 89th Annual Meeting, Nashville, TN, June 23-28*.

Main H.H., Chinkin L.R., and Roberts P.T. (1996) Analysis of VOC data in support of pollutant transport studies in Shasta County, California. In *Measurement of Toxic and Related Air Pollutants. Proceedings of an Air & Waste Management/U.S. Environmental Protection Agency International Specialty Conference, Raleigh-Durham, NC, May 7-9*, Air & Waste Management, Pittsburgh, PA, (STI-1581), pp. 67-74.

Heiken J., Austin B., Pollack A., Coe D., Eisinger D., and Chinkin L. (1996) Estimation of local fleet characteristics and activity data for improved emission inventory development. Presented at the *6th Coordinating Research Council On-Road Vehicle Emissions Workshop, San Diego, CA, March 18-20*.

Chinkin L.R., Main H.H., Rocke D.M., and Chang D.P.Y. (1995) Development of improved temporal, spatial and temperature algorithms for use in emissions modeling: a work plan. Paper presented at the *Air & Waste Management Association Emission Inventory Programs and Progress Conference, Research Triangle Park, NC, October 11-13* (STI-1542).

Chinkin L.R., Ryan P.A., and Reiss R. (1995) A critical evaluation of biogenic emission systems for photochemical grid modeling in California. Paper presented at the *Air & Waste Management Association Emissions Inventory Programs and Progress Conference, Research Triangle Park, NC, October 11-13* (STI-1541).

Korc M.E., Jones C.M., and Chinkin L.R. (1995) Use of PAMS data to evaluate the Texas COAST emission inventory (preliminary results). Presented at the *Air & Waste Management Association Emission Inventory Programs and Progress Conference, Research Triangle Park, NC, October 11-13* (STI-1566).

Blanchard C.L., Roberts P.T., Chinkin L.R., and Roth P.M. (1995) Application of smog production (SP) algorithms to the Coastal Oxidant Assessment for Southeast Texas (COAST) data. Paper No. 95-TP15.04 presented at the *Air & Waste Management Association 88th Annual Meeting & Exhibition, San Antonio, TX, June 18-23*.

Chinkin L.R., Main H.H., Collins J.F., and Young J.R. (1995) Long-term trends in precipitation chemistry in southern California. Paper presented at the *Air & Waste Management Association Acid Rain & Electric Utilities: Permits, Allowances, Monitoring & Meteorology Conference, Tempe, AZ, January 23-25* (STI-1500).

Chinkin L.R., Korc M.E., and Janssen M. (1994) Comparison of emission inventory and ambient concentration ratios of NMOC, NO_x, and CO in the Lake Michigan air quality region. Paper presented at the *Air & Waste Management Association Emission Inventory Application and Improvement Conference, Raleigh, NC, November 1-3* (STI-1434).

Korc M.E., Roberts P.T., Chinkin L.R., Lurmann F.W., and Main H.H. (1994) Reconciliation of emission inventory and ambient data for three major regional air quality studies. In *Transactions, Air & Waste Management Association Regional Photochemical Measurement and Modeling Studies Conference, San Diego, CA, November 8-12, 1993*, Air & Waste Management Association, Pittsburgh, PA, (STI-1405).

Seigneur C., Chinkin L.R., Morris R.E., and Kessler R.C. (1994) Conceptual plan for air quality and meteorological modeling in the San Joaquin Valley. In *Planning and Managing Regional Air Quality Modeling and Measurement Studies: A Perspective Through the San Joaquin Valley Air Quality Study and AUSPEX*, P.A. Solomon and T.A. Silver eds., CRC Press, Inc., Boca Raton, FL, 79-106.

Chinkin L.R, Korc M.E., Roberts P.T., Lurmann F.W., and Main H.H. (1993) Reconciliation of emission inventory and ambient data: current state of knowledge and implications for emission inventory preparation. Paper presented at the *Air & Waste Management Association The Emission Inventory: Perception and Reality Conference*, Pasadena, CA, October 18-20.

Reynolds S.D., Tesche T.W., Dye T., Roberts P., Franzon D.E., Chinkin L.R., and Reid S.B. (1993) Assessment of planned northeast ozone transport region modeling activities. Paper No. 93-WA-69A.01 presented at the *Air & Waste Management Association 86th Annual Meeting*, Denver, CO, June 14-18.

Roberts P.T., Korc M.E., Main H.H., Chinkin L.R., and Lurmann F.W. (1993) Reconciliation of emission inventory and ambient data in the Lake Michigan Air Quality Region. Paper No. 93-WP-100.05 presented at the *Air & Waste Management Association 86th Annual Meeting*, Denver, CO, June 14-18.

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APPENDIX C

STATEMENT OF COMPENSATION

Sonoma Technology, Inc. (STI) has been compensated at $290 per hour for Lyle R. Chinkin's services to the United States Department of Justice (USDOJ). For any deposition or trial testimony the USDOJ will compensate STI at a rate of 150% of Mr. Chinkin's rates in effect at the time the testimony is provided.

APPENDIX D

PREVIOUS EXPERT TESTIMONY

I, Lyle R. Chinkin, have testified as an expert witness at a trial or deposition in the past four years. The cases in which I have testified are as follows:

- United States of America, et al. v. Cinergy Corp.., et al. C.A. No. IP99-1693 C-M/S
- State of North Carolina ex rel. Roy Cooper, Attorney General v. Tennessee Valley Authority, Civil Action No. 1:06CV20, (W.D.N.C.)

APPENDIX E

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APPENDIX F

ELECTRONIC FILES

This appendix describes the electronic files provided with this report.

Daily CAMx PSAT Results

Plots showing year-2005 daily impacts of excess emissions from the Monroe Power Plant on regional $PM_{2.5}$ concentrations are included on a CD appended to this report. Plots are provided in animated GIF and PDF formats for all 364 days modeled with CAMx PSAT.

Exhibit 2

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA Plaintiff, v. DTE ENERGY COMPANY, and DETROIT EDISON COMPANY Defendants.	)

DECLARATION OF
ETHAN CHATFIELD

I, Ethan Chatfield, declare as follows under penalty of perjury:

1. I am currently an environmental engineer employed by the U.S. Environmental Protection Agency Region 5 (EPA Region 5), Air and Radiation Division. I have been an engineer with EPA Region 5 Air & Radiation Division since March 2003.

2. EPA Region 5 is the regional office of EPA that covers the states of Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. EPA Region 5 is headquartered in Chicago.

3. From March 2003 to August 2007, I was an environmental engineer in the Permits Section (Air Programs Branch) of EPA Region 5 Air and Radiation Division. As an engineer in the Permits Section, my responsibilities included reviewing and writing New Source Review (NSR) and Title V operating Permits to ensure compliance with the Clean Air Act (CAA), the State Implementation Plan (SIP) and other applicable requirements.

4. Since August 2007, I have been an environmental engineer with EPA Region 5's Air Enforcement and Compliance Assurance Branch (Air Enforcement Branch) of the Air and Radiation Division. As part of my duties as an environmental engineer in the Air Enforcement Branch, I am responsible for supporting enforcement actions brought by EPA Region 5 for compliance with requirements of the CAA and its implementing regulations. Primarily, my cases involve enforcement of the New Source Review requirements under the CAA against coal-fired electric utilities.

5. I am the Region 5 co-lead in the investigation and development of cases involving coal-fired utilities for EPA Region 5. My duties consist of identifying sources of potential violations, drafting and reviewing CAA Section 114 information requests, reviewing and analyzing case files, which primarily include CAA Section 114 information request responses, calculating emission increases based on information obtained from, among other sources, CAA Section 114 information request responses, including Generation Availability Data System (GADS)[1] event data. I have conducted, and assisted other EPA Region 5 environmental engineers in, the investigation and development of 17 cases against coal-fired electric utilities.

6. Generally, New Source Review is a preconstruction permitting program that requires an owner or operator of a Major Stationary Source to, among other things, obtain a construction permit and install appropriate pollution controls known as best available control technology (BACT)[2] prior to commencing construction of a Major

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[1] GADS is a collection of operating information reported by utilities with the purpose of improving the performance of electric generating units.

[2] NSR consists of two programs, depending on whether the area is in attainment with the applicable National Ambient Air Quality Standard. Both programs, Prevention of Significant Deterioration ("PSD") and Non-attainment New Source Review, are applicable here. For the purposes of this declaration, the programs are similar enough that I cite only the PSD requirements.

Modification. A Major Modification is defined as a physical change or change in the method of operation that results in a significant net emission increase. The applicable NSR rules that apply to sources in Michigan can be found at Part C of the Act, 42 U.S.C. §§ 7470–7492, and the federally-approved State Implementation Plan ("SIP") regulations at Michigan Admin. Code R. 336.2801 to 336.2830. Basically, for electric steam generating units, an emission increase is determined by comparing the selected 24-month baseline period from the five years prior to the commencement of a physical change with the post-project projected actual emissions. If the difference in the emissions for an individual pollutant exceeds the significance thresholds listed in the regulations, then there is a significant emissions increase. There are exemptions and exclusions from the definition of a physical change and projected emissions increase, including routine maintenance, repair and replacement and emissions increases that the source could have accommodated and are unrelated to the project.

A. DTE Coal-Fired Electric Generating Stations

7. DTE and its subsidiaries own and/or operate several power plants. These plants include the Belle River, Harbor Beach, Monroe, River Rouge, St. Clair, and Trenton Channel Stations (collectively the "DTE Plants"). The Belle River Station is a power plant in East China, Michigan which includes two coal-fired units with a maximum rated net capacity of 635 MWs each. The Harbor Beach Station is a power plant in Harbor Beach, Michigan that has a single coal-fired unit with a maximum net rated capacity of 121 MWs. The Monroe Station is a power plant in Monroe, Michigan which includes four coal-fired units each with a maximum rated net capacity between 817 and 823 MWs. The River Rouge Station is power plant in River Rouge, Michigan

which includes two coal-fired units with a maximum rated net capacity of 278 and 302 MWs, respectively. The St. Clair Station is a power plant in East China, Michigan which includes six coal-fired units with a maximum rated net capacity of 168, 172, 178, 164, 346, and 465 MWs, respectively. The Trenton Channel Station is a power plant in Trenton, Michigan which includes five coal-fired units with a maximum rated net capacity of 58, 58, 58, 58, and 540 MWs, respectively.

8. Based on data reported by DTE to EPA's Clean Air Markets Division (CAMD), Belle River emitted 28,070 tons of SO_2 and 10,435 tons of NO_X in 2009. Monroe emitted 85,898 tons of SO_2 and 20,374 tons of NO_X in 2009. Harbor Beach emitted 1,044 tons of SO_2 and 460 tons of NO_X in 2009. River Rouge emitted 14,945 tons of SO_2 and 4,340 tons of NO_X in 2009. St. Clair emitted 28,930 tons of SO_2 and 9,378 tons of NO_X in 2009. Trenton Channel emitted 25,443 tons of SO_2 and 5,161 tons of NO_X in 2009. All of the stations in total emitted 184,332 tons of SO_2 and 50,149 tons of NO_X in 2009. All the stations qualify as major emitting facilities under the CAA. The plants also emit significant amounts of PM. In addition, the SO_2 and NO_X emissions from the plants contribute to the formation of fine particulates, while the NO_X emissions from the plants contribute to ozone.

9. At all relevant times, each of the six power plants listed above and each coal-fired generating unit at those plants were each a "major emitting facility" and a "major stationary source," within the meaning of the Act and the Michigan SIP for NO_X, SO_2, and PM.

B. CAA Section 114 Information Requests

10. EPA Region 5 issues information requests under Section 114 of the CAA

to, among other things, investigate whether a person may be in violation of any requirement of the CAA and its implementing regulations. EPA Region 5 routinely sends Section 114 information requests to emission sources subject to the CAA's requirements.

11. Electric generating facilities (utilities) are emission sources subject to the CAA and to Section 114 of the CAA.

12. On November 12, 1999, April 16, 2008, September 11, 2008, June 25, 2009 and May 24, 2010, EPA Region 5 issued information requests under Section 114 of the CAA to DTE (collectively the "Information Requests").[3] The Information Requests sought information relevant to DTE's electric generating stations to determine compliance with the Clean Air Act, including New Source Review.

13. In its response to EPA's Information Requests, DTE provided, among other documents, over two dozen letters dated between 2002 and 2009 notifying the Michigan Department of Environmental Quality (recently renamed the Michigan Department of Natural Resources and Environment) that it was about to have a planned outage at a specified plant and unit(s) during which DTE intended to perform identified maintenance, repair, or replacement activities (Notification Letters). In these Notification Letters, DTE briefly explained what activities were about to be performed, stated that the activities were routine maintenance, repairs, and/or replacements, provided brief emissions estimates, and asserted that the activities would not result in a significant net emissions increase and, therefore, would not trigger the requirements of NSR.

14. On March 12, 2010, DTE submitted a notification letter to the Michigan Department of Natural Resources and Environmental (MDNRE). DTE did not send a

[3] EPA Region 5 also submitted much narrower CAA Section 114 information requests for information related to the 2010 Monroe 2 boiler rehabilitation project on May 28, June 2, and June 4, 2010.

copy of the March 12, 2010 notification letter to EPA. On May 21, 2010, a representative of Sierra Club sent a copy of the notification to EPA.

15. On April 26, 2010 I discovered a news article dated April 22, 2010 titled "Extreme Makeover: Power Plant Edition" by Charles Slat in an on-line version of the Monroe News, a local newspaper. This news article, which includes a photograph of the open boiler, describes that DTE Energy is "in the midst of one of the largest maintenance shutdowns in the history of the Monroe Power Plant." The article described that the project would last about 83 days, employ more than 600 construction workers, and cost about $65 million to complete. The article states that the focus of the work involves replacement of the economizer, replacement of about 2,000 square feet of boiler water wall tubing, and replacement of the reheater pendants in the boiler. A true and correct copy of the article is Exhibit D to my declaration.

C. EPA Inspection Of Monroe Unit 2

16. On June 2, 2010, Mark Ackerman (another EPA Region 5 Environmental Engineer) and I conducted an inspection pursuant to Section 114 of the CAA of the on-going construction activities at the Monroe power plant. The day after the inspection, Mr. Ackerman wrote up a report memorializing what he and I observed and what we were told by DTE during the inspection. A true and correct copy of the inspection report is Exhibit A to my declaration. The report was made based on information we obtained shortly before the report was written. It is part of the regular practice of EPA engineers to write such reports memorializing inspection findings and to maintain those reports. The report reflects factual findings resulting from an investigation made pursuant to Section 114 of the CAA.

17. During this inspection, DTE informed EPA that the company

* has not obtained any permits or received any applicability determinations from the MDNRE for the on-going construction activities;

* currently has no plans to install BACT-level controls for NO_X emissions (i.e. a Selective Catalytic Reduction system or SCR); and

* does not plan to complete the installation of its SO_2 emissions control system (i.e. a Flue Gas Desulfurization system or FGD) until the Spring of 2014.

During this inspection, we learned further details about the project, including:

* Economizer was replaced in whole and included the removal and replacement of 323 tube elements with 642 elements, creating an 80-foot wide array of tubes.

* The new economizer was redesigned to reduce historic flow and tube pluggage problems.

* DTE stated that this is the first time in the 37 year life of the plant that either the economizer or reheater pendants have been replaced.

During our inspection, we asked for certain project specific documents, which DTE later provided. A true and accurate copy of the documents provided by DTE in response to our request is Exhibit F to my declaration.

D. CAA Section 113 Notice of Violation

18. As required by Section 113 of the CAA, EPA Region 5 issues Notices of Violation to notify the state in which the source is located and the owner or operator of the source that the Agency has found violations of the Clean Air Act and applicable State Implementation Plan at the source and provide the source an opportunity to confer with

EPA concerning the alleged violations.

19. Electric generating facilities (utilities) are emission sources subject to the CAA and to Section 113 of the CAA.

20. In the two and a half years I have been with the Air Enforcement Branch, EPA Region 5, I have been involved with the issuance of 9 of these Section 113 Notices of Violations to coal-fired power plants.

21. In response to the 9 Notices of Violations I handled, sources typically request an opportunity to confer with EPA to discuss the allegations in the NOVs. Such conferences are informally referred to as NOV conferences.

22. Typical topics of discussion during NOV conferences include the allegations in the NOV and potential paths towards resolution of the alleged violations.

23. On July 24, 2009, EPA issued an NOV to DTE alleging that DTE violated, among other requirements, New Source Review and its implementing regulations at DTE's Belle River, Monroe, River Rouge, St. Clair, and Trenton Channel Generating Stations.

24. On September 14, 2009, DTE representatives met with EPA for an NOV Conference to discuss the allegations in the NOV. Representatives of DTE included Paul Fessler, Vice President, Fossil Generation, DTE; Skiles Boyd, Vice President, Environmental Management and Resources, DTE; Lillian Woolley, Senior Environmental Engineer, DTE; Michael Solo, Counsel, DTE; and William Brownell, Counsel, Hunton & Williams. Representatives of EPA included, among others, myself and Sabrina Argentieri, Associate Regional Counsel, EPA Region 5.

25. During the September 14, 2009 NOV conference, Mr. Brownell

represented that DTE had submitted a series of notification letters to the State of Michigan explaining why various projects did not trigger NSR.

26. During the NOV conference, in response to Mr. Brownell's representation, Ms. Argentieri explained that EPA disagreed with DTE's analysis of NSR applicability in the notification letters. Ms. Argentieri invited Mr. Brownell to contact her to discuss in detail why EPA disagrees with DTE's analysis in the notification letters. Ms. Argentieri repeated her invitation multiple times. To my knowledge, neither Mr. Brownell nor any other DTE representative contacted Ms. Argentieri or any other EPA representative to discuss the analyses in the notification letters.

27. On June 4, 2010, EPA issued an NOV stating that DTE violated NSR for the construction activities at Monroe Unit 2 which commenced on or about March 13, 2010.

D. Documents

28. True and correct copies of the following documents that I am personally familiar with are being filed with my Declaration as Exhibits A through J in support of the United States' motion for preliminary injunction:

A. June 3, 2010 Notes from M. Ackerman and E. Chatfield (U.S. EPA) of June 2, 2010 Monroe Generating Station Inspection

B. December 8, 2009 DTE Energy Press Release entitled, "DTE Energy Environmental Project Will Create 900 Jobs"

C. March 12, 2010 Letter from Kelly Guertin (DTE Energy) to William Presson (Michigan Department of Environmental Quality)

D. April 22, 2010 Article by Charles Slat from "The Monroe Evening News" entitled, "Extreme makeover: Power plant edition"

E. June 4, 2010 Notice and Finding of Violation issued to DTE Energy Co. and Detroit Edison Co.

F. Excerpts of DTE Documents Produced in Response to Request During EPA's June 2, 2010 Inspection of Monroe Generating Station (CBI: FILED UNDER SEAL)

G. June 3, 2010 Letter from Michael Solo (DTE Energy) to Mark Palermo (U.S. EPA) enclosing Detroit Edison response to June 2, 2010 CAA Section 114 Information Request

H. Direct Testimony of Paul Fessler before Michigan Public Service Commission, Case No. U-15768

I. May 28, 2010 Letter from Phillip Brooks (U.S. EPA) to Michael Solo (DTE Energy) requesting information pursuant to CAA Section 114

J. June 4, 2010 Letter from Phillip Brooks (U.S. EPA) to Michael Solo (DTE Energy) requesting information pursuant to CAA Section 114

I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 27 2010, at Evanston, Illinois.

Ethan Chatfield

Ethan Chatfield

Exhibit 2-A

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604

DATE: June 3, 2010

SUBJECT: Clean Air Act Inspection of Detroit Edisons Monroe Generating Station, in Monroe Michigan

FROM: Mark Ackerman, Chemical/Environmental Engineer
Ethan Chatfield, Environmental Engineer
Air Enforcement and Compliance Assurance Section (IL/IN)

THRU: Brent Marable, Chief
Air Enforcement and Compliance Assurance Section (IL/IN)

TO: File

Date of Inspection June 2, 2010

Attendees
Mark Ackerman, U.S. EPA
Ethan Chatfield, U.S. EPA
Brian Carley, MDRNE (Michigan Department of Natural Resources and Environment)
R.C. (Chuck) Larlham, Principal Environmental Engineer Monroe Power Plant (MonPP)
Joe Robinson, Unit 1 and 2 Side Leader MonPP
Clare Jennings, Environmental
Randy DeWulf, MonPP Manager
Rob Stoiber, MonPP FGD Plant Manager
Leonard Kantoca, Outage Manager
Christopher Hessex, Unit Engineer
Michael Solo, Attorney
Lillian Wooley, Environmental Supervisor
Franklin Warren, MonPP Director

Purpose of Inspection

The announced inspection of the Monroe generating station was performed to gather additional information regarding the construction project currently taking place at Monroe Unit 2, specifically information regarding the economizer, reheater, and waterwall tube replacements.

Company Description

Physical Location/Mailing Address: Monroe Power Plant

3500 East Front Street
Monroe, Michigan 48161

Opening Conference – June 2, 2010

Mark Ackerman, Ethan Chatfield (EPA inspectors), and Brian Carley (MDRNE) arrived and entered the Monroe plant at approximately 1:20 pm. Upon entering the plant the EPA inspectors were lead to a conference room where the DTE personnel above were waiting. The EPA inspectors introduced themselves, and stated the purpose of the inspection was to gather information regarding the Unit 2 construction project that was currently taking place. The EPA inspectors stated they would like to go over a list of questions they had prepared beforehand, followed by a tour of Unit 2.

The Unit 2 outage began on March 13, 2010, and DTE originally expected to tie the unit back to the grid on June 9. However, DTE mentioned that they were currently 3-days ahead of schedule and would likely tie Unit 2 into the grid as early as June 6, 2010.

DTE indicated that the overall installation of the boiler components (economizer, reheater pendants, and waterwall tubes) had been completed and they were currently hydrotesting the boiler. DTE expected the hydrotest to be completed in the evening of June 2, 2010, and if the hydrotest didn't identify any leaks in the boiler components then DTE would begin the startup sequence to bring the boiler back on line. EPA inspectors asked when DTE expected to start burning coal in the Unit 2 boiler. DTE stated that burning coal would be contingent on the water chemistry, and the new equipment response (glitches, or problems may arise due to the new equipment that was installed that could delay start up of Unit 2, but that they would likely burn coal in the afternoon on June 3, 2010 (but as late as Friday, June 4th)

EPA inspectors asked some general questions regarding the construction status of Unit 2. Based on these questions DTE provided the following information. The cranes used to lift the boiler tubes to the upper elevations of the boiler building had been demobilized. The Unit 2 boiler had not been completely closed up because an earlier hydrotest had identified a leak. The construction workforce peaked at approximately 700 contractors, and is currently at about 100 or less. The construction contractor used to install the boiler components was URS/WGI (DTE indicated that URS had bought our WGI).

EPA inspectors asked specific questions about the Unit 2 economizer. DTE stated that the economizer tubes were supplied by Doosan Babcock. DTE also stated that this was the first time the Unit 2 economizer had been replaced, and that the current project replaced the Unit 2 economizer in its entirety. DTE stated that the reason for the replacement of the Unit 2 economizer was due to increased forced outages due to misaligned tubes (affects the flue gas flow around the tubes causing unwanted velocity gradients inside the boiler), and pluggage in the backpass. DTE also stated that over time they have had to plug approximately 10% of the economizer tubes.

EPA inspectors asked specific questions about the Unit 2 reheater pendants. DTE stated

Babcock and Wilcox supplied the reheater pendant tubes. DTE stated that this was the first time the Unit 2 reheater pendants had been replaced in their entirety. The current project only replaced the vertical reheater pendants (there are two sections of horizontal reheater tubes that were not replaced). EPA noted that in the GADS data, there are cause codes that distinguish between first, and second reheater. Based on this distinction identified in the GADS data the EPA inspectors asked if the reheater pendants DTE replaced were the first, second, or both. DTE stated that they do not make any distinction between the first, and second regarding the reheaters and they were not clear why it was identified as such in the GADs data. DTE stated that the reason for the replacement of the Unit 2 reheater pendants was due to increased forced outages related to creep failure.

EPA inspectors asked specific questions about the waterwall tubes. DTE stated that the waterwall tubes were a stock item at the plant because portions of the waterwall tube assembly are replaced frequently during outages (planned and forced). DTE stated that the scope of the current outage involved patchwork (replacing miscellaneous section of worn waterwall tubes) from the 4th floor and below. DTE stated that in whole, approximately 2,000 square feet of waterwall tubes were replaced, or approximately 4% of the total waterwall tubes. DTE stated that the reason for replacing various sections of the waterwall tubes was to reduce forced outages due to this component as a result of corrosion. EPA asked if this unit was experiencing waterwall outages prior to the planned outage. DTE stated that they experienced 1-2 waterwall outages, but most of the outages were due to the economizer.

EPA inspectors asked specific questions about the cost of the boiler tube replacements. DTE stated that approximately $65 million (material and installation) was spent on the Unit 2 outage. The Outage Manager stated that approximately $30 million was spent in the boiler area, $15 million in the generator/exciter area, and $15 million on general operating and maintenance expenses. EPA asked for a price breakout of the individual boiler components, but DTE stated that they did not have that information readily available, but that they would provide the information to the EPA following the inspection. However, DTE stated that as a general rule of thumb the price break out is typically around 20% material purchase, and 80% installation.

EPA inspectors asked some general questions about the Unit 2 boiler. DTE stated that the original manufacturer of the Unit 2 boiler was Babcock and Wilcox. DTE stated that the rated net generation before and after the current project is 795 MW. DTE stated that the gross generation of the Unit 2 boiler is 823 MW, and the heat rate is 7624 mmBTU/hr. EPA asked if the 7,624 heat input was significantly below what was currently being achieved and reported in the Clean Air Markets Division (CAMD) database. Lillian Wooley from DTE stated that CAMD slightly over-reports heat input due to flow measurement variations and that this is a nominal capacity.

EPA inspectors asked what other work besides the replacement of the boiler components was carried out during the outage. DTE stated that the following additional work was performed during the outage:

1. Corrective maintenance on valves in the boiler systems,
2. Chemical cleaning to remove deposit build up on inside of boiler tubes,
3. Generator was rewound,
4. Replaced exciter,
5. Routine maintenance on the turbine stop control valves,
6. replaced the generator lead box,
7. South boiler feed pump assembly was swapped out,
8. North boiler feed pump turbine was repaired,
9. 4K (4000 hours) inspection on 4 of 7 coal mills,
10. replaced approximately a dozen burner lines (lines used to transfer coal to the burners,
11. Replaced upper 10 feet of 3 of the 7 coal silos due to erosion,
12. Electrical system on service transformer was replaced, and some cables on others

DTE roughly estimated that the size of the laydown area was roughly the size of a football field, but it was extremely difficult to estimate the exact size.

EPA asked specific questions about future work planned for Units 1, 3, and 4 at the Monroe power plant. DTE then described their planned outages. Based on the description, DTE stated that they have a major periodic outage every four years on each unit, and that the four year planned outages cycle between the units sequentially. For instance in 2010 Unit 2 underwent a planned periodic outage, in 2011 Unit 3 is scheduled for a planned periodic outage, and so on. Chris Hessex, the Unit Enginer stated that this outage was however larger than their typical cyclical outage because they replaced the economizer at the same time as the reheater pendants. DTE stated that they don't typically replace the economizer and reheater pendants at the same time. EPA then asked what boiler work DTE was planning for the 2011 Unit 3 periodic outage. DTE stated that they planned on replacing the vertical reheater pendants, the exciter, and waterwall tubes on Unit 3. EPA then asked if the economizer on Unit 3 was going to be replaced. DTE stated that the Unit 3 economizer would not be replaced, and that the Unit 2 economizer was replaced because it was in the worst condition in the whole plant.

EPA asked specific questions about DTE's current plant for controls at the Monroe power plant. DTE stated that they just received the permit from Michigan for the scrubber flue for Units 1 and 2, and that they had permission from the state to install 4 scrubbers. The scrubbers on Unit 3 and Unit 4 are installed, and in operation. The underground work (pilings, and foundations) for the Unit 1 and 2 scrubbers has commenced. DTE stated that the Unit 1 scrubber will be complete in Fall of 2013, and Unit 2 will be completed in Spring of 2014. DTE stated that they did apply for and received a non-PSD construction permit for the installation of SCRs on Units 1, 3, and 4. MDNRE reminded DTE that they had withdrawn their application for the installation of a SCR on Unit 2 because the 18-month window for construction was about to elapse. DTE stated that they have not started construction and have don't have any plans for submittal of a new application for the installation of an SCR on Unit 2, but the decision on whether to install a SCR depends on outcome of the discussions with EPA.

EPA stated that they believed the Monroe power plant was currently located in an area classified as non-attainment for ozone, and $PM_{2.5}$. DTE confirmed that the Monroe power plant was in fact non-attainment for ozone, and $PM_{2.5}$.

DTE also stated that their union labor force could potentially go on strike during the week of June 7, 2010. DTE mentioned this because it may affect their ability to respond within the requested 45 day time period in the 114 request since the DTE personnel who would normally be tasked with preparing the response may be required to undertake operational duty in order to keep the Monroe power plant running during the strike.

Inspection – June 2, 2010

EPA, MDNRE, and DTE personnel exited the conference room at approximately 3:05pm, walked through the turbine room to the plant rooftop where they could view the Unit 2 outage laydown area, emission controls and surrounding plant area. EPA took several videos and photos of the surrounding area. Everyone then walked to the 13th floor, the top of the plant/boiler to view the location where the reheater pendants were lifted into the boiler. There was no longer an opening on the side of the boiler; insulation and siding were reinstalled over the previous opening. DTE noted that this was the site of the photo in the news article. DTE stated that the article was written by a local newspaper to promote the construction activity (i.e. jobs) at the plant. There was no major opening in which to view the reheater pendants, so EPA took photos through a small permanent side port to view inside the boiler. There was still an opening in the side of the boilerhouse, approximately 20 foot by 15 foot where the reheater tubes were lifted into the boilerhouse and into the boiler. There was still various debris, extra paneling, insulation, etc, surrounding the boiler that likely still needed to be cleaned up.

Everyone then walked down 4 floors to the bottom of the reheater to see the bottom of the pendants via another small permanent side port. Plant staff indicated that the reheater spans approximately 4 floors and the length of the boiler.

Everyone then walked down to the area surrounding the installation of the new economizer tube banks. DTE explained that the permanent rail/crane system used for replacing air heater baskets was partially used to transport the new economizer into the boilerhouse. There was no longer an opening on the side of the boiler; insulation and siding were reinstalled over the previous opening. DTE staff explained that two major steam pipes were temporaily removed to allow space for the crane to lift the new economizer into the boiler. EPA was able to view the bottom of the new economizer through a small permanent side port.

Everyone then walked down to the 4th floor, where DTE staff noted that the bolts were removed on a permanent port on both sides of the boiler and the waterwall tubes were fed into the boiler for replacement.

The inspection ended at 3:45pm. DTE agreed to let EPA know within a day how long it would take to get the 5 items requested (below) during the opening conference.

Follow-up Information Requested by EPA

During the inspection EPA inspectors requested certain information that DTE was unable to provide during the inspection, but agreed to provide following the inspection. Those items are as follows.

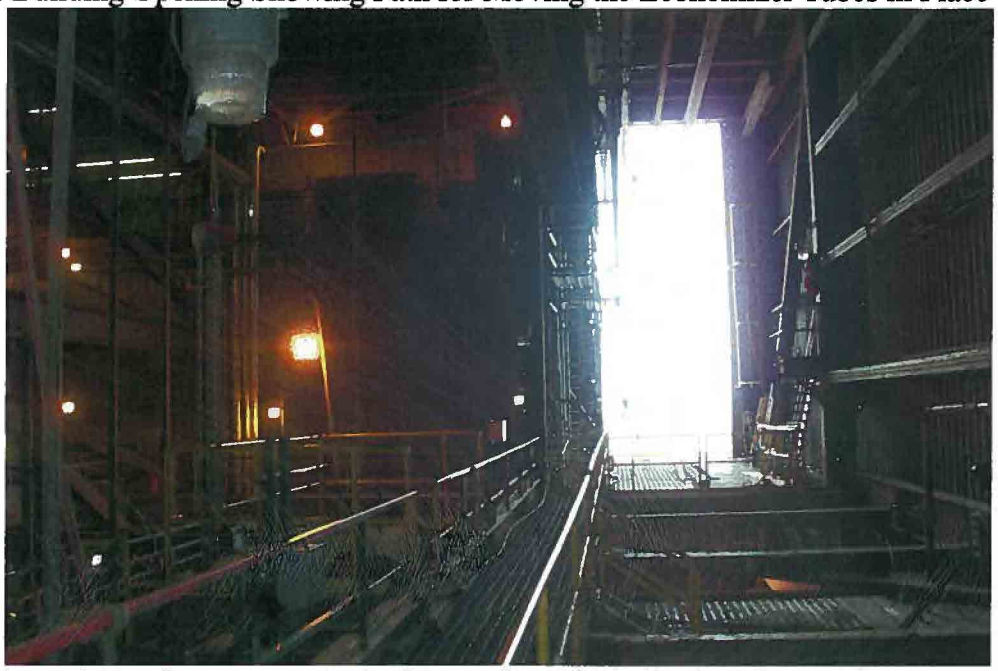
1. Budget information showing the break out of cost for the individual boiler components (economizer, reheater pendants, and waterwall tubes)
2. Capital appropriation requests (or PMPs) for the individual boiler components (economizer, reheater pendants, and waterwall tubes)
3. Expedited GADS data for Unit 2 from August of 2008 through the present
4. Most recent "outage status report".
5. Organizational chart showing the level of the people in attendance at the inspection relative to one another.

Photos

Staging Area

The brownish orange racks shown in the photo were used to hold the economizer tubes, and reheater pendant tubes.

Boiler Building Opening Showing Path for Moving the Economizer Tubes in Place

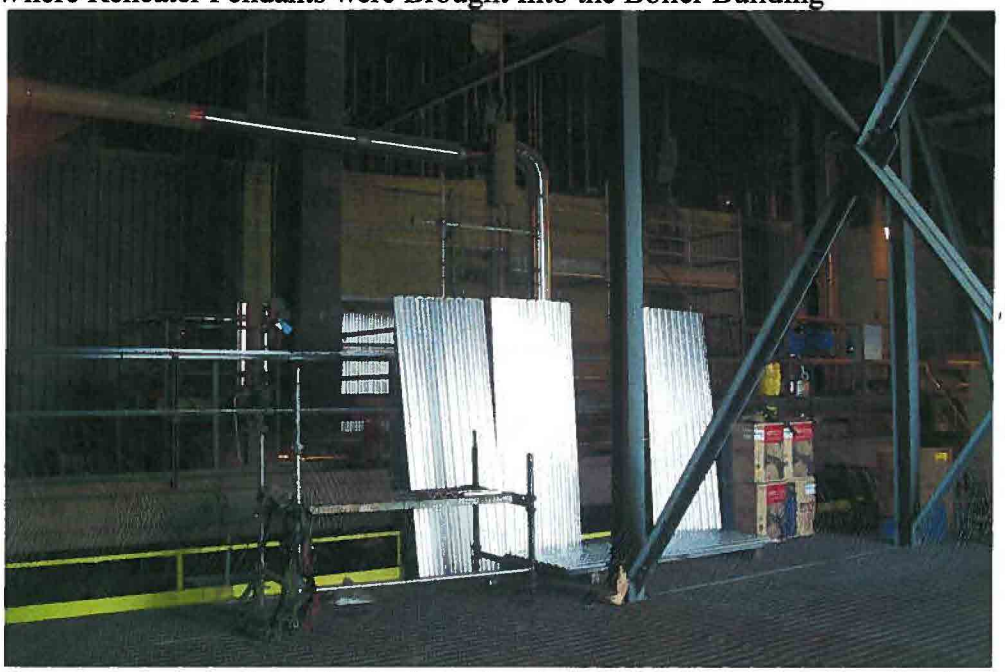


This photo shows the temporary opening made to the boiler building to allow the economizer tubes to be transferred from the staging area to inside the boiler building for installation.

Economizer Tubes

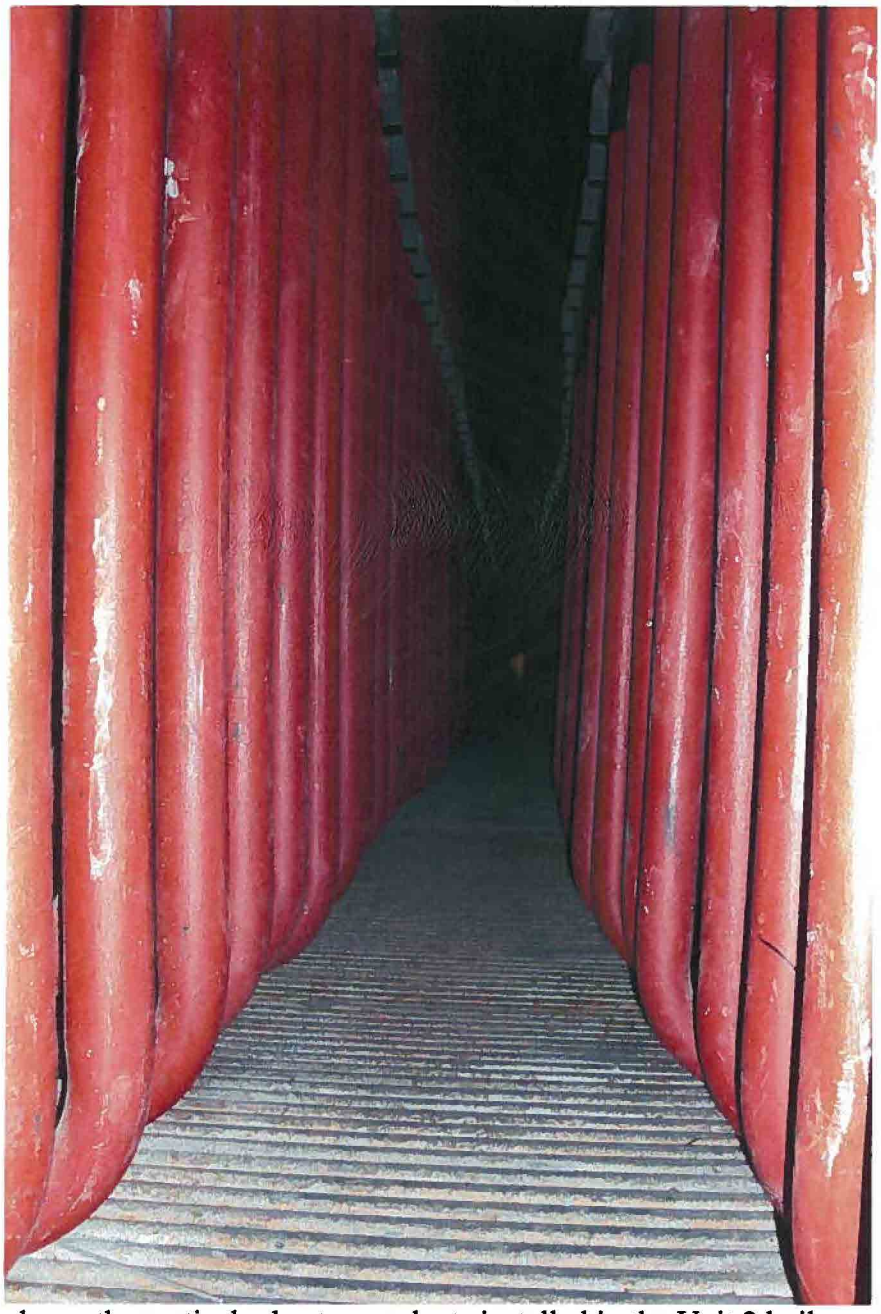
This photo shows the economizer tubes installed in the Unit 2 boiler.

Area Where Reheater Pendants were Brought Into the Boiler Building



This photo shows where the boiler had previously been opened up to allow for the installation of the reheater pendants (surface that has not had the metal lagging put back in place).

Vertical Reheater Tubes



This photo shows the vertical reheater pendants installed in the Unit 2 boiler.

Exhibit 2-B

DTE Energy News Releases

DTE Energy Environmental Project Will Create 900 Jobs

- $600 million Monroe Power Plant expenditure will improve air quality

PRNewswire
MONROE, Mich.
(NYSE:DTE)
Dec 8, 2009

MONROE, Mich., Dec. 8 /PRNewswire/ -- DTE Energy announced today that it will begin a major environmental construction project in the first quarter of 2010 at its Monroe Power Plant. The $600 million project will create 900 jobs and be one of the largest construction projects in Michigan over the next few years.

DTE Energy will be installing two additional flue gas desulfurization (FGD) systems at the coal-fired Monroe Power Plant to further reduce sulfur dioxide (SO2) emissions. FGDs, also known as scrubbers, reduce SO2 emissions by about 97 percent.

The Monroe Power plant, which consists of four individual generating units, began operation of two scrubbers earlier this year. When all four scrubbers are operational, they will nearly eliminate sulfur dioxide emissions from the plant.

The Monroe Power Plant is the first coal-fired power plant in Michigan to operate with scrubbers. It's also the first plant in Michigan that operates scrubbers and selective catalytic reduction (SCR) systems - which reduce nitrogen oxide emissions by about 90 percent. When operating together on the same generating unit, the combination also eliminates 75 to 90 percent of mercury emissions.

"The Monroe Power Plant today is among the cleanest and most efficient coal plants in the country and the completion of the final scrubbers and SCR projects will place it among the very best in the world," said Skiles Boyd, vice president, environmental management and resources, DTE Energy. "In addition to this project, we are planning for additional emissions control systems at our other fossil fuel plants."

Steve Kurmas, president of Detroit Edison, DTE Energy's electric utility, added, "Scrubbers are the best available technology for controlling SO2 emissions, and we believe that installing these systems on our largest and most efficient coal-fired power plant is in the best interest of our customers, the local community, the environment and our company."

The $600 million scrubber project will create 600 construction jobs. The construction workers will come primarily from the local building trades unions.

It's also estimated that the project will generate another 300 jobs and an additional $300 million in indirect economic activity in the region.

"The planned investment in the final two scrubbers continues an emissions control construction program that began 10 years ago and has cost $1.7 billion to date," said Ron May, senior vice president, major enterprise projects, DTE Energy. "This investment makes a significant improvement to air quality in the region and supports the long-term operation of the Monroe Power Plant, which is a cornerstone of Detroit Edison's generating fleet."

May added that the $1.7 billion investment over the last 10 years created approximately 900 construction jobs. In addition, 40 full-time permanent jobs have been created to operate the scrubber systems.

Three of the Monroe plant's four generating units are equipped with SCRs and plans call for starting construction on the final SCR in 2011. That project is projected to cost $330 million and will create another 400 construction jobs. At the peak of construction activity on the scrubbers and the SCR, a total of 1,000 construction workers will be employed. The total investment in the two scrubbers and the fourth SCR will approach $1 billion.

DTE Energy (NYSE: DTE) is a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. Its operating units include Detroit Edison, an electric utility serving 2.2 million customers in Southeastern Michigan, MichCon, a natural gas utility serving 1.2 million customers in Michigan and other non-utility, energy businesses focused on power and industrial projects, coal and gas midstream, unconventional gas production and energy trading. Information about DTE Energy is available at www.dteenergy.com.

SOURCE: DTE Energy

Web site: http://www.dteenergy.com/

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Key Contacts

Members of the Media may contact us at 313.235.5555

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Exhibit 2-C

DTE Energy Company
One Energy Plaza, Detroit, MI 48226-1221

DTE Energy

VIA CERTIFIED MAIL

March 12, 2010

Mr. William Presson, Acting Section Supervisor
Permit Section
Air Quality Division
Michigan Department of Environmental Quality
525 W. Allegan
Constitution Hall - 3rd Floor North Tower
P.O. Box 30260
Lansing, MI 48933

Re: **2010 Planned Outage Notification - Monroe Power Plant (B2816), Unit 2**

Dear Mr. Presson:

DTE Energy periodically removes its generating units from service for up to three months to perform maintenance, repair, and replacement activities that cannot otherwise be done with the unit in operation. Typically, this occurs on a 2-3 year cycle. Occasionally a unit is taken out of service for a planned shorter duration to perform less extensive work. During the upcoming twelve (12) week outage at the Monroe Power Plant on Unit 2 that begins on or about March 13, 2010, the following major projects are being undertaken: (1) boiler system repairs and replacements; (2) turbine repairs and replacement; (3) electrical repairs and replacement; and (4) draft system repairs and replacement. These project are exempt under Michigan air rules and no permitting activity is required (see Attachment A). In the electric utility industry, these projects represent routine maintenance, repair and replacement activities.

We are providing notice that these projects are taking place based on the recently promulgated Michigan Prevention of Significant Deterioration (PSD) rules [R336.2801-2830] that became effective on December 4, 2006. Prior planned outage notifications were submitted under the federal New Source Review (NSR) rules promulgated on December 31, 2002 and that became effective in Michigan on March 3, 2003 (the 2002 rules). The 2002 rules required notification, additional record keeping, and annual reporting whenever *"there is a reasonable possibility that a project that is not a part of a major modification may result in a significant emissions increase...."* For the reasons discussed below, DTE Energy continues to believe there is no reasonable possibility that the proposed project will result in a significant emissions increase and thus, the requirements do not apply. However, until USEPA and/or the federal courts provide a clear definition of what constitutes routine maintenance, repair and replacement, DTE Energy will follow the requirements of Michigan Air Rule 1818(3). Accordingly, this outage notification for Monroe Unit 2, and all subsequent outage notifications submitted by DTE Energy will continue to follow the format of prior notifications, even though there is no expected increase in emissions as a result of the planned projects. We continue to believe this notice is not required by federal or state regulations.

The NSR applicability test requires a comparison of past actual and projected emissions. *"Baseline actual emissions"* are defined in Michigan Air Rule (MAR) 1801(b). The baseline period for defining past emissions for Monroe Unit 2 was originally established for the 12 week outage in February 2005 to be the two-year period in calendar years 2000-2001. That baseline is being replaced for this periodic outage. The new baseline is May 2005-April 2007. Net generation and capacity factor data for the new period were obtained from the DTE Energy Power Plant Performance Management (P3M) system records. Particulate emissions were based on fuel characteristics and EPA emission factors. Heat input, sulfur dioxide, and nitrogen oxide emissions were obtained from continuous emission monitoring system (CEMS) data presented in the EPA Annual Acid Rain Scorecard reports. Baseline emissions and other operating characteristics are shown in Table 1.

"Projected actual emissions," as defined in MAR 1801(ll), are also shown in Table 1, along with a comparison of projected and baseline actual emissions. This comparison shows that the projects will not result in an emissions increase. The projected actual emissions in Table 1 were calculated as follows: First, PROMOD projections (production cost model output) were calculated based on the unit's expected post-outage maximum annual utilization during the period 2010-2014 with fuel characteristics similar to the baseline period. The expected post-outage maximum annual utilization (estimated to occur in 2013) was obtained from the PROMOD analysis contained in the 2010 PSCR Annual Report issued on September 10, 2009 as required by the Michigan Public Service Commission. As required under the new rules we then excluded from the PROMOD projections *"...that portion of the unit's emissions following the project that an existing unit could have accommodated ... and that are also unrelated to the particular project," including increases due to demand and market conditions or fuel quality per MAR 1801(ll)(ii)(C).* (See Table 1)

It should be pointed out that emissions and operations fluctuate year-to-year due to market conditions and in any individual year could very well exceed baseline levels. Obviously, since the baseline represents a 2-year average, one of those years was above the baseline and one below. At some point in the future, baseline levels may be exceeded again, but not as a result of this outage. Future unit utilization is also a function of expected electricity market conditions. Many factors influence market demand – weather, availability of other units, transmission limitations, electrical system security, etc. Moreover, fuel quality could change. As mentioned above, the Michigan air rules direct one to exclude from projected actual emissions "...that portion of the unit's emissions following the project that an existing unit could have accommodated ... and that are also unrelated to the particular project," including increases due to demand growth or fuel quality changes per MAR 1801(ll)(ii)(C).

Additionally, Part 18 of the Michigan Air Rules allows an existing utility steam generating unit to use a different baseline period for each pollutant under the definition of "Baseline Actual Emissions" in R336.2801(b)(i)(C) as follows:

> *"(C) For a regulated new source review pollutant, if a project involves multiple emissions units, then only 1 consecutive 24-month period shall be used to determine the baseline actual emissions for the emissions units being changed. <u>A different consecutive 24-month period may be used for each regulated new source review pollutant.</u>" [Emphasis added]*

Accordingly, a pollutant-specific baseline for sulfur dioxide ("SO_2") was chosen as July 2006-June 2008. The pollutant-specific baseline for nitrogen oxides ("NO_X") was chosen to be October 2006-September 2008. The pollutant-specific baseline for particulate matter (PM) was chosen to be January 2008-December 2009.

All of the replacement components are identical or functionally equivalent to the equipment now in service, and they do not change the basic design parameters of Monroe Unit 2, which will continue to meet enforceable emission and operational limitations. Moreover, the Utility Air Regulatory Group (UARG), an organization of which DTE Energy is a member, has submitted to the EPA NSR Docket during prior comment periods a list of repair and replacement activities that utilities must perform to keep electric generating facilities operational.[1] These activities are considered routine in the electric utility industry. Furthermore, MAR 1801(aa)(iii)(A) specifies that routine maintenance, repair and replacement activities are not major modifications. Therefore, Part 18 requirements do not apply to these projects.

If you have questions on this notice, please contact me at (313) 235-4698 or via email at gossiauxk@dteenergy.com or you may contact Mr. Wayne Rugenstein at (313) 235-7023 or via email at ***rugensteinw@dteenergy.com***.

Regards,

Wayne A. Rugenstein for

Kelly L. Guertin
Staff Environmental Engineer
Environmental Management & Resources

Attachments

FILE: MONPP U2 Planned Outage 2010 - NSR Notification.docx

Cc: C. E. Jennings
R. C. Larlham
Scott Miller – AQD Jackson
F. D. Warren

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[1] DTE has previously provided to your office a copy of the UARG document as part of the Monroe Unit 1 Planned Maintenance Outage Notification dated January 21, 2004.

ATTACHMENT A

Monroe Power Plant Unit 2 Outage Summary

The following activities will be performed during the outage scheduled to begin on or about March 13, 2010, and are exempt under the Michigan Air Pollution Rules as outlined below:

- **Boiler System Repairs and Replacements** – Replacement of economizer tubes; replacement of reheat pendants; replacement of a section of water wall tubes and burner cells; and boiler tube chemical cleaning with the replacement of 210 valves. These activities are exempt under MAR 285(a).
- **Turbine System Repairs and Replacements** – Rewind MTG rotor; install static exciter; replacement of generator lead box; overhaul of north boiler feed pump turbine & rebuild south boiler feed pump; and install boiler feed pump TSI. These activities are exempt under MAR 285(a).
- **Electrical System Repairs and Replacements** – Replace system service transformer #62; replace 4160V cables from system service transformers; rebuild 9-4160V circuit breakers. These activities are exempt under MAR 285(a).
- **Draft & Fuel Burning Repairs and Replacements** – Replace ten air heater gas side expansion joint. This activity is exempt under MAR 285(a).

Table 1
Monroe Power Plant - Unit 2
Comparison of Actual and Projected Actual Emissions & Operations

Period	Baseline Actual per MAR 1801(b)(1)(2)	Pollutant - Specific Baseline Actual Emissions for NO_X per MAR 1801(b)(1)(2)	Pollutant - Specific Baseline Actual Emissions for SO_2 per MAR 1801(b)(1)(2)	Pollutant - Specific Baseline Actual Emissions for PM per MAR 1801(b)(1)(2)	PROMOD Projection per MAR 1802(ll)(ii)(A)(3)	Emissions Excluded per MAR 1802(ll)(ii)(A)(3)	Projected Actual Emissions per MAR 1802(ll)(ii)	Emission Change
	May 2005-April 2007	October 2006-September 2008	July 2006-June 2008	January 2008-December 2009	January 2013-December 2013			
Unit Electrical Capacity, MW	795	795	795	795	795			
Net Generation, MWh	4,983,296				5,748,000			
Annual Capacity Factor	85.5%				82.5%			
Heat Input, mmBtu	47,335,146	44,343,031	45,802,027	43,742,775	54,974,000			
SO2, lb/mmBtu			1.32		1.23			
NOx, lb/mmBtu		0.47			0.53			
PM, lb/mmBtu				0.02	0.02			
SO2, tons			30,115		33,816	3,701	30,115	0
NOx, tons		10,398			14,494	4,096	10,398	0
PM, tons				498	615	117	498	0

Notes:
(1) Michigan Air Rule (MAR)
(2) Baseline values are a 12-month average of a selected 24-month consecutive operating period
(3) PROMOD projections are based on the maximum utilization for the period 2010-2014 as shown in the DTE Energy - Detroit Edison Power Supply Cost Recovery (PSCR) 2010 Annual Report (dated 9-10-09) as required by the Michigan Public Service Commission

Exhibit 2-D

Flat Rock's season

SPEED ZONE PAGE 4B

Monroe's top grads

CLASSROOM PAGE 8B

THE MONROE Evening News

WWW.MONROENEWS.COM 2007 NATIONAL ESOP CO. OF THE YEAR

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Since 1825 – NO. 111 (USPS 359-400) MONROE, MICH. Thursday, April 22, 2010 75 cents

GM reinstates Allen dealership

■ The Cadillac-Chevrolet outlet will continue to be part of the automaker's network provided it meets certain conditions.

BY CHARLES SLAT
ctslat@monroenews.com

Allen Chevrolet-Cadillac is getting a new lease on life after winning General Motors' approval to continue as a franchised dealership.

Owner Tom Allen said he received word Wednesday night that he would be able to keep the franchise, after being lopped from the list of dealers during the automaker's financial woes last year.

"We got our letter from GM that they want to reinstate us," Mr. Allen said today.

It means the franchise will have a larger inventory of new cars on its lot within weeks, will be rehiring staff and adding others, and upgrading the facility at 15180 S. Dixie Hwy. in Monroe Township.

It also means it will continue to be the only Cadillac dealership in the area and now will be the only Chevrolet franchise in Monroe County, due to the closing of the North Towne dealership in Bedford Township.

"We'll let bygones be bygones. Now we're going to move forward," Mr. Allen said.

Last year, when GM's financial crisis worsened and the economy contin-

See **DEALERSHIP,** Page 11A

Road commission chairman to resign

BY JOSHUA KENNEDY
Evening News staff writer

An impending election for Monroe County Board of Road Commissioners has little to do with current road board Chairman Anthony Majauskas stepping down.

ANTHONY MAJAUSKAS

"It's time," the longtime chairman said Tuesday morning from his newly built retirement home on Sage Lake near West Branch. "My wife retired and we are moving up here. We just got our occupancy permit."

Mr. Majauskas last week sent his official resignation to the Monroe County Board of Commissioners, which has been responsible for appointing road board members. The letter sets April 25 as the date of his resignation and it will be considered by the board at its regular meeting next week.

But its timing is somewhat odd.

Mr. Majauskas' six-year term as road commissioner is set to expire Dec. 31. But the county board in May last year voted to make the three road commissioners elected positions. Mr. Majauskas' seat is the first up for election.

Road Commissioner Robert (Mickey) Duffey's seat will be filled by election in 2012 when his current six-year term expires, and Commissioner Richard Turner's seat will be up for election in 2014 when his term expires.

No one has filed a petition with the Monroe County clerk to run for Mr. Majauskas' post, but a few people — a clerk this morning said two or three — have taken petitions out. The deadline to file for the partisan job is 4 p.m. May 11.

Candidates will face-off on the Aug. 2 primary ballot if they are of the same party. The top vote-getters of each party will face each other in the Nov. 3 general election for the six-year elected term.

The county board next week will have two options: Appoint a replacement to fill Mr. Majauskas' unexpired term or leave the position vacant until the November election. The new commissioner will assume office in January.

To Mr. Majauskas, who has served the road board for nearly 12 years, an election is a mistake, one that opens all sorts of issues that have yet to be resolved by a county board mired in its own quest for financial stability.

"One problem (with electing the road board members) is the qualifications," Mr. Majauskas said. "The way it's been, (the county board members) have gotten top pick who they wanted for the positions based on qualifications.

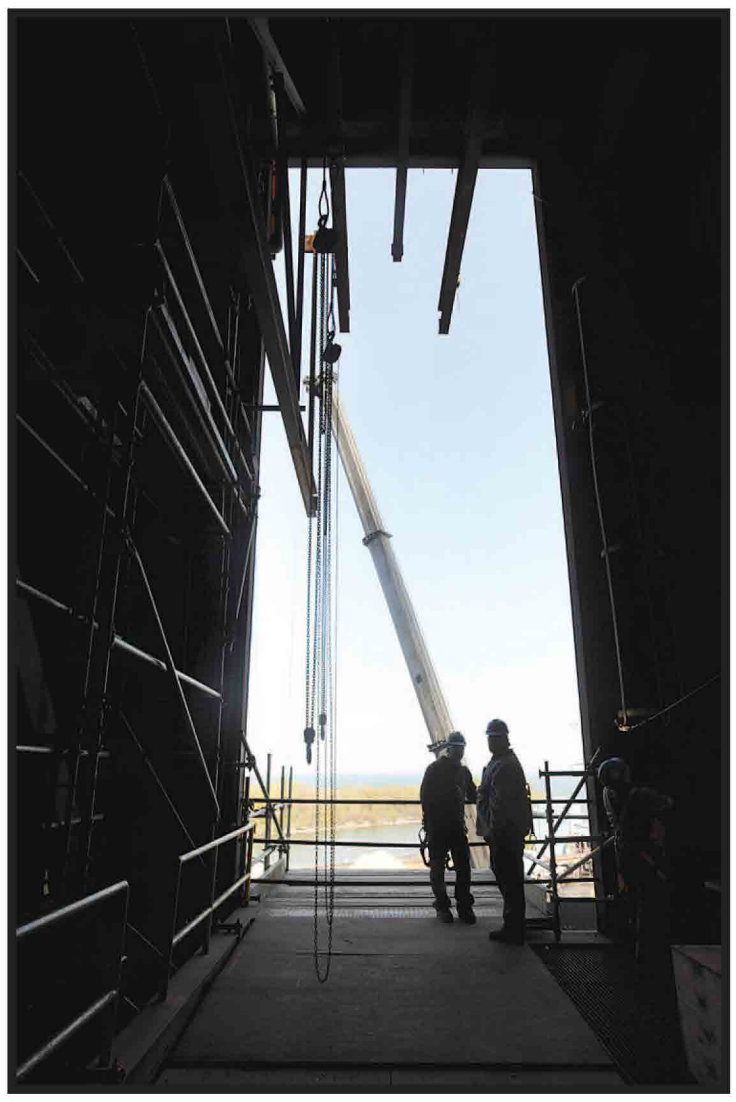
"Now, it's going to be based on popular vote."

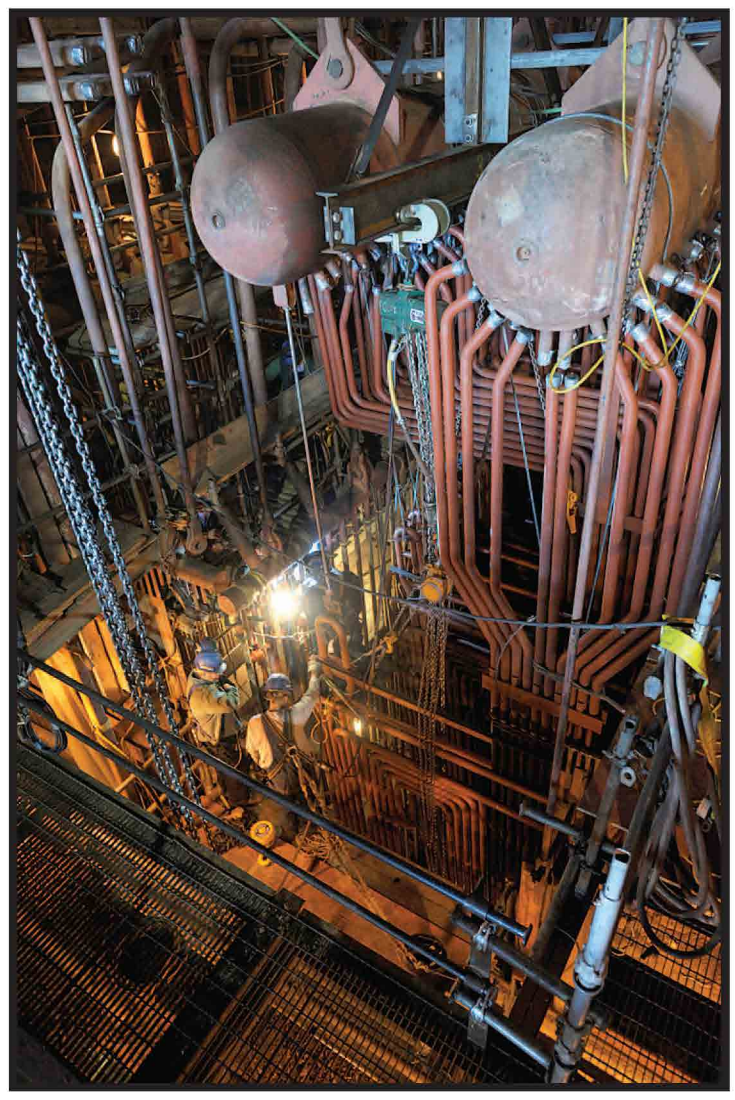
Mr. Majauskas said the county board members' citations of frequent phone calls and complaints as motive to make the road commissioners electable is evidence that the panel is shirking its duties.

"The county commissioners have always said, 'Oh we're tired of getting all these phone calls …' That's a bunch of B.S. They just want to be able to say to the people calling that, 'Hey, you elected

See **MAJAUSKAS,** Page 11A

Extreme makeover:





— Evening News photos by KIM BRENT

Workers (left photo) stand near an access hole cut near the top of DTE Energy's 12-story Monroe Power Plant to allow cranes to hoist new equipment into the plant as part of a major overhaul of the Unit 2 boiler. Crews (right photo) work on a boiler reheater unit, part of the $65 million refurbishment at the facility.

Power plant edition

■ One of the four boiler units at the Monroe Power Plant is getting a $65 million rehab to boost its efficiency.

BY CHARLES SLAT
ctslat@monroenews.com

DTE Energy is in the midst of one of the largest maintenance shutdowns in the history of its Monroe Power Plant, a project that will last about 83 days, employ more than 600 construction workers and pump about $65 million into the economy.

The project has involved cutting a giant access hole near the top of the 12-story power plant to remove some parts of the massive boilers that have been in place since the generating station began operating nearly 40 years ago.

"We've been planning this for 10 months," said Chris Denunzio of Monroe, a project leader with URS, a San Francisco-based engineering and construction firm that's coordinating the work.

The coal-burning plant has four boiler/turbine-generator units, each capable of generating about 800 megawatts of electricity. Each massive multi-story boiler is lined with thousands of tubes that carry water, which is converted to steam by the fire in the boiler and then used to spin turbines connected to an electrical generator.

The project is in day 40 of the work, approximately halfway to completion.

Focused on the Unit 2 boiler, the scope of the work includes removing large sections of the tubing that has corroded or weakened over time and replacing them with new tubing. About 2,000 square feet of tubing or "water wall" sections are being replaced.

Replacement of the "economizer," a massive array of tubed sections that act much like a radiator and increase boiler efficiency, also is part of the job. About 642 of the sections are being installed to create an 80-foot wide array.

The heavy 36-foot long sections are hoisted from the ground by giant crane to a hole that was cut into the side of the plant to provide access. They then are loaded onto a crane monorail specifically built for the work inside the plant to carry them to the location where they are being installed. More than 500 lifts by crane will be needed to carry out the maintenance project, DTE officials said.

Large sections of piping in the reheater pendants of the boiler also are

See **PLANT,** Page 11A

Economy key focus in Michigan GOP race for governor

■ Oakland County Sheriff Mike Bouchard, Attorney General Mike Cox, state Sen. Tom George, U.S. Rep. Pete Hoekstra and Ann Arbor businessman Rick Snyder are vying to win the party's nomination in the August primary.

EAST LANSING, Mich. (AP) — Five Republicans seeking to become Michigan's next governor tried to convince potential voters Wednesday that they could turn around the state's struggling economy and fix its budget problems.

The candidates met face-to-face in the first of a series of debates sponsored by the Michigan Republican Party. The hourlong debate was held at Michigan State University and televised live on WLNS-TV.

The candidates tried to present a stark contrast to the policies of outgoing Democratic Gov. Jennifer Granholm, who can't run again this year because of the state's term limits law.

Michigan has had the nation's highest unemployment rate for the past four years. The rate was 14.1 percent in March.

Most of the candidates spoke at recent tea party events and are trying to appeal to the GOP base with a message of lower taxes and smaller government.

Bouchard said businesses, residents and families are leaving Michigan "in droves" and the state needs a more efficient, less costly government.

"We can't ask them for more, because they don't have it," Bouchard said.

See **DEBATE,** Page 11A

Two sections

Classified 10-11B
Classroom 8-9B
Community 6-7B
Entertainment 9A
Local 3A, 5A
Speed Zone 4B
Sports 1-4B

TODAY'S OBITUARIES

Diane Eikum, 71, of Ottawa Lake

Elizabeth Pasko, 92, formerly of Monroe

Betty J. Briskey, 82, formerly of Dundee

Douglas E. Robinson, 95, of Monroe

Vincent J. Petrarca, 43, of Erie

Darcy Symington, 51, formerly of Monroe

Page 11A

WEATHER

TONIGHT
Mostly clear
36°

FRIDAY
63°

2:10-cv-13101-BAF-RSW Doc # 87 Filed 08/06/10 Pg 3 of 3 Pg ID 171

Creator of $15 Minnesota Twins logo dies at age 80

ST. PAUL, Minn. (AP) — The St. Paul illustrator who created the enduring Minnesota Twins logo of two players shaking hands across a river has died of cancer at age 80.

Ray Barton was paid $15 in 1961 to create the image, never thinking it would become the team's official logo. Barton assumed it would be used on cups at Metropolitan Stadium.

Barton created art for advertising agencies and other companies in the Twin Cities, including Target, but it was his image of Minnie and Paul that became best known. It's displayed on the Twins' uniforms and pennants and was turned into a giant sign that looms over the outfield at the team's new ballpark.

Barton's widow, Joyce Barton, says he died Saturday in home hospice care.

Barton's son, Tony Barton, said his dad never really liked the logo.

"It wasn't one of his crowning achievements," Barton said. "He was a cartoonist, a writer, a creative director, but he never really thought it was that great. And if you look at it close, it really isn't. Anyone out of art school could have done it."

But Clyde Doepner, the Twins' historian, said the logo represents Twins tradition.

"It goes back to '61," Doepner said. "When you think of Killebrew, Carew, even when you think of Puckett, you think of that (logo)."

Deaths

Betty Jane Briskey

April 24, 1927-April 19, 2010

Betty Jane Briskey passed away April 19, 2010 five days before her 83rd birthday.

She was born April 24, 1927 to Dora (Vermette) and LeRoy Rosenerantz in Dundee, MI.

Betty was employed at Craft Master and The Toledo Hospital before retiring.

She was preceded in death by her parents; brothers Cletus, Albert, and Noah, husband Carl and daughter Ruth Ann.

She leaves to cherish her memories daughters, Susan La Fountaine, Linda (Marton) Biery, Janette Case-Day and Paula (Dennis) Clark; son, Edward (Sandy); sisters, Eva West and Annabelle (Grant) Wright and many loving grandchildren and great-grandchildren.

Betty's family would like to thank Stein Hospice for their support and excellent care. Betty's long hair locks are being donated to give cancer patients a new beginning.

A memorial mass will be celebrated at a later date at Our Lady of Mount Carmel Church in Temperance, MI. Her ashes will then be reunited with her husbands in Florida. Arrangements have been trusted to Gerner-Wolf-Walker Funeral Home and Crematory, 216 Washington Street, Port Clinton. Online condolences may be shared with the family at www.walkerfuneralhomes.com.

Diane "Stoney" Eikum

Jan. 27, 1939-April 19, 2010

Diane "Stoney" Eikum, 71, of Ottawa Lake, passed away peacefully in her sleep on April 19, 2010 at Parkcliffe Community in Toledo after a long battle with Alzheimer's disease.

Diane was born January 27, 1939 in Atlanta, Georgia to Marguerite (Wise) and Robert Earl Linler and moved to Toledo as a child.

She attended Whitmer High School and worked as an LPN and Cardiac Cath Tech first at Toledo Hospital for 26 yrs. and then St. Vincent Mercy Medical Center for 12 years, where she had many friends and was well respected for her expertise in the cath lab. Diane had a talent for soothing a troubled or frightened patient with her easy way and kind words.

She was a lover of animals, especially dogs and horses, and raised German Shepherds and Yorkshire Terriers. Her life-long love of horses was nurtured by beloved step-father Freddie Wellinger, who signed her up at Douglas Meadows Riding Academy as a teenager. She spent many happy hours there, riding with friends and caring for the horses.

Diane continued to ride and board horses at the farm in Ottawa Lake, Michigan, where she lived with husband Kevin.

Diane is survived by Husband Kevin, daughter Shelley (Joe) Allore, Grandchildren Kristin and Amanda Allore, brother-in law Chuck Slater, niece Cindy Slater, nephew Charles Slater, and many good friends.

She was preceded in death by her Mother and Step-father Marguerite and Fred Wellinger, Father Robert Linler, and Sister Vivian Slater.

Friends may call at the Reeb Funeral Home 5712 N. Main St. Sylvania, OH, Friday April 23rd from 5 – 8 p.m.

Those wishing to give memorials in Diane's memory are asked to consider the Toledo Humane Society or the Heartland Hospice.

Friends wishing to share a memory of Diane, view her Tribute Video, or offer a condolence to her family are encouraged to do so at www.reebfuneralhome.com.

Darcy Symington

April 20, 2010

Mr. Darcy Symington, age 51, passed away on Tuesday, April 20, 2010.

Darcy graduated from Monroe High School in 1976, and later enlisted in the United States Army. During his years of service to our country, which included 17 months of foreign duty, he earned several achievement awards, and attained the rank of Specialist 4th class.

Darcy was preceded in death by his parents, Edward and Audrey Symington, formerly of Monroe, his son Brandon, as well as 4 brothers and sister, a brother in law, and several sisters in law, numerous nieces and nephews, and some very special friends.

Arrangements have been made at the Newcomber Funeral Home in Toledo, with private family services to be held.

Memorial contributions may be made to the charity of the donors choice.

Elizabeth "Betty" Pasko

March 25, 1918-April 12, 2010

Elizabeth "Betty" Pasko, age 92, formerly of Monroe, died from pneumonia at 12:30 a.m. April 12, 2010 in Candor, N.C., Sandy Ridge Assisted Living.

At her bedside were sons John E. Pasko, M.D., of Monroe and Richard S. Pasko, D.C., of Seven Lakes, N.C.

Betty was born in Girard, Ohio of Hungarian parents, Andrew and Mary (Horvath) Chako. She outlived seven brothers and sisters. She married John E. Pasko Sr. on June 11, 1936 in West Virginia.

Working through WWII as a waitress, and while husband John labored at Youngstown Sheet and Tube, they owned and operated Pasko Dairy Store in Girard, Ohio from 1949 to the late 1970s. Retiring then to Clearwater, Fla., John and Betty enjoyed sunshine, boating and sewing.

Betty was a member of the still-existent Jolly Stitchers sewing and card club in Ohio. She was an avid crossword and Scrabble player. While living in Florida, Betty earned her GED certificate. Previous to North Carolina, Betty lived at Alice Lorraine and Marian Place in Monroe.

Her husband preceded her in 1997.

She leaves behind sons John (Rosalie) Pasko of Monroe and Richard (Bonnie) Pasko of Seven Lakes., N.C. Grandchildren include John A. of Ypsilanti, Jason C. and Jonathan E. (Laura) Pasko, M.D., of Monroe. Great grandchildren include Jessica M., Margaret Rose and Kathryn A. of Monroe. Four more grandchildren reside in Ohio, John Patrick, Steve, Julie and Andy, and three more great-grandchildren, Kayla, Gus, and Zack.

Services were held last week at West Bend, N.C., with cremation and final interment next to her husband at Calvary Cemetery in St. Petersburg, Fla.

Home sales in U.S. rise more than expected

WASHINGTON (AP) — Home sales rose more than expected in March, reversing three months of declines, as government incentives drew in buyers and kicked off what's expected to be a strong spring selling season.

Sales of previously occupied homes rose 6.8 percent to a seasonally adjusted annual rate of 5.35 million last month, the highest level since December, the National Association of Realtors said today.

February's sales figures were revised downward slightly to 5.01 million.

"The spring selling season will be a success and probably the most active we're seen in years," said Stuart Hoffman, chief economist at PNC Financial Services Group.

Sales are now up 18 percent from their low in early 2009, but are still down 26 percent from their peak in fall 2005. March's results had been expected to rise about 5 percent to 5.28 million, according to economists surveyed by Thomson Reuters.

The results show the housing market is stabilizing after a devastating bust. But the true test will be whether the market can stand on its own after federal tax credits expire at the end of this month.

Sales rose in every region, surging more than 7 percent in the Midwest and South, 6.6 percent in the West and 6 percent in the Northeast.

"It's a very broad-based recovery," said Lawrence Yun, the Realtors' chief economist.

The median sales price was $170,700, up almost 4 percent from $164,600 a month earlier and nearly unchanged from $170,000 in March 2009.

The inventory of unsold homes on the market was up 1.5 percent at 3.6 million. That's an eight month supply at the current sales pace.

Sales nationally had declined over the winter, eroding gains made last fall and summer. The downward direction troubled economists because the government has taken unprecedented steps to support the housing sector.

For several months, home shoppers didn't feel rushed after lawmakers extended the deadline to qualify for tax incentives.

The government is offering an $8,000 credit for first-time buyers and $6,500 for current homeowners willing to buy and move into another property.

But now time is running out. Buyers must sign contract offers by April 30 to qualify, and real estate agents say that's spurring sales.

"Many people who otherwise wouldn't be on the market for a home want to take advantage of these tax credits," said Kathi McLeod, sales manager for Windermere Real Estate in Boise, Idaho.

From Page 1A

Debate (cont.)

Cox has suggested cutting taxes by $2 billion. State government already has a projected deficit of about $1.7 billion for the fiscal year that starts Oct. 1.

Snyder said the state's business taxes and tax incentive programs need revising to better spark business development.

"We're in a crisis here," Snyder said. "We've been in a crisis so long in Michigan we don't act like it's a crisis anymore."

George, a doctor, said Michigan must cut its health care costs to get its finances in order.

"Health care costs are stealing our future," George said.

Many of the candidates have said education will be key in getting Michigan out of its economic doldrums. Some criticized decisions that have cut education funding in the state, including last year's decision to not fund the state's main college scholarship, the Promise grant.

"The state couldn't have made a worse decision," Hoekstra said of the decision to cancel the program that thousands of students were expecting to help them pay tuition.

A few of the candidates traded jabs to try and differentiate themselves from each other. Cox questioned the strength of Snyder's position against abortion and his record as a Gateway executive. Snyder said he opposes abortion but supports embryonic stem cell research.

Snyder labeled Cox a career politician and said he was "making up stuff."

Cox wasn't happy about how he was characterized.

"I'm not going to be lectured about being a career politician," Cox, a former Marine and assistant county prosecutor, said after the debate.

Cox highlighted his fights as attorney general, including opposition to some Blue Cross Blue Shield of Michigan rate increases and the federal health care overhaul.

"Tough times call for a tough leader," Cox said. "I have a history of standing up and fighting tough fights."

Hoekstra said candidates don't need to get personal.

"The people of Michigan are expecting better from us," he said after the debate.

Bouchard hoped to give his campaign a boost starting Thursday by showing cable TV ads statewide. Snyder was the first candidate to show TV ads.

Democrats running for governor are Lansing Mayor Virg Bernero, House Speaker Andy Dillon and state Rep. Alma Wheeler Smith.

Plant (cont.)

being replaced. It's the first time that the plant has replaced economizer and reheater components at the same time.

Each new part and new weld is inspected or checked using X-ray scanning that will reveal structural or welding flaws much in the manner a medical X-ray will show a bone fracture. "If we find something even the size of a speck of pepper, we have to grind that out," Mr. Denunzio said.

He said the outage overall is a "large, labor-intensive job."

Crews are working in two 10-hour shifts, six days a week to get the job done. Mr. Denunzio said an effort is made to use mainly local unionized workers, including boilermakers, pipefitters, carpenters and laborers. Labor costs represent more than $40 million of the project About 100 Detroit Edison skilled-trades employees also are involved in the work.

Mr. Denunzio said an effort also is being made to team younger trades workers with seasoned veterans to provide a learning opportunity for the younger ones.

Part of the work also involves installing a new nine-ton exciter, a device that provides voltage to create the electromagnetic field needed for the generator rotor to produce electricity. The rotor itself has been removed and sent out to be rewound.

Boiler feedwater pumps also are being refurbished and hundreds of other parts are being replaced, reworked or serviced. The outage includes about 2,700 individual work projects.

The bottom line is that the plant boiler unit will run far more efficiently and have and extended life, officials said.

Similar work is being planned in the years ahead for other boilers at the plant, which continue to operate while the project is under way. The project began March 13 and might be completed by the first week of June.

Meanwhile, the plant also continues to be the focus of other unrelated work that is adding costly equipment to further reduce its emissions.

Dealership (cont.)

ued to deteriorate, Mr. Allen initially had indications he would be spared in GM's plan to trim the number of dealerships. Later, he learned that the company planned to pull his Cadillac franchise.

Then Congress told GM it wanted to see deeper cuts as a prerequisite for federal financial aid. "When Congress told GM it had to cut deeper, I don't know what happened but I think they went into the panic mode," Mr. Allen said.

The company said it also would pull its Chevy franchise.

"We went from fighting the economy to fighting GM and the economy," he said. "There were hundreds of dealers that were in the same boat as us."

Mr. Allen said the grassroots efforts of dealership employees, customers, suppliers and the dealers themselves helped get legislation passed last December providing for third-party arbitration of dealership disputes.

Before the arbitration began, a GM representative visited the dealership and found that the Allen franchise had pre-existing agreements with GM to take certain steps to maintain the franchise. It became obvious the company wasn't aware of the pre-existing agreements that GM had approved for his dealership, Mr. Allen said.

Mr. Allen said he appreciated customers who argued with GM that the dealership should be retained.

"We had customers that told GM reps, 'We want our dealer back,'" he said. "It was in God's hands. God placed these people there."

The uncertainty during the process put the future of the dealership in some limbo and forced Mr. Allen to resort to procuring new cars through other dealers rather than from GM itself. He also had to cut staff.

Now he has a five-year contract and expects to have more new cars on the lot in a matter of weeks.

Also during the period of uncertainly, Mr. Allen also had to combat health problems due to a spinal ailment.

"I'm getting better slowly," he said. "I'm sure this is going to help out a lot."

Majauskas (cont.)

them,' that it's nottheir problem," Mr. Majauskas said.

He sees the population centers of Bedford and Frenchtown townships as having an unfair advantage when electing road commissioners and it's even possible all three could come from one community — which could mean good roads for them, not so much for others.

And then there is the question of salary.

"That should be one of the most interesting parts," Mr. Majauskas said. "Other elected officials have health benefits and retirement. Will the new guy? What about the other two guys? One commissioner will get paid this and have benefits and what about the other two?

"This will be pretty interesting to see how it all shakes out."

Because the positions will be elected, the county's salary compensation committee will be charged with setting an applicable pay rate.

DEATH NOTICES

Douglas E. Robinson

April 21, 2010

Douglas E. Robinson, 95, of Monroe died at 5:30 p.m. Wednesday in Tendercare of Monroe.

Arrangements by Bacarella Funeral Home.

Vincent James Petrarca

April 19, 2010

Vincent James Petrarca, 43, of Erie died Monday in his home.

Arrangements by Bedford Funeral Chapel, Temperance.

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Daily puzzle on page 2.

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Exhibit 2-E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF:	)	
	)	
	)	
DTE Energy Company	)	**Proceedings Pursuant to**
and	)	**Section 113(a)(1) and (a)(3) of the**
The Detroit Edison Company	)	**Clean Air Act,**
	)	**42 U.S.C. §7413(a)(1) and (a)(3)**
	)	
Detroit, Michigan	)	**EPA-HQ-2010-MI-1**
	)	
	)	

NOTICE AND FINDING OF VIOLATION

The U.S. Environmental Protection Agency (EPA) is issuing this Notice and Finding of Violation (Notice) under Section 113(a)(1) and 113(a)(3) of the Clean Air Act, 42 U.S.C. § 7413(a)(1) and § 7413(a)(3). The authority to issue this Notice has been delegated to the Director, Air Enforcement Division, Office of Enforcement and Compliance Assurance, U.S. EPA. EPA finds that DTE Energy and the Detroit Edison Company (collectively herein, DTE) are violating the Clean Air Act (Act), 42 U.S.C. §§ 7401 *et seq.*, at its Monroe power plant, as follows:

STATUTORY AND REGULATORY BACKGROUND

Prevention of Significant Deterioration

1. When the Act was passed in 1970, Congress exempted existing facilities, including the coal-fired power plants that are the subject of this Notice, from many of its requirements. However, Congress also made it quite clear that this exemption would not last forever. As the United States Court of Appeals for the D.C. Circuit explained in *Alabama Power v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979), "[t]he statutory scheme intends to 'grandfather' existing industries; but…this is not to constitute a perpetual immunity from all standards under the PSD program." Rather, the Act requires grandfathered facilities to install modern pollution control devices whenever the unit is proposed to be modified in such a way that its emissions may increase.

2. On June 19, 1978, EPA promulgated regulations pursuant to Part C of Title I of the Act. 43 *Fed. Reg.* 26403 (June 19, 1978).

3. The Prevention of Significant Deterioration (PSD) provisions of Part C of Title I of the Act establish specific provisions applicable to the construction and modification of sources located in areas designated as either attainment or unclassifiable for purposes of meeting the NAAQS. *See* 42 U.S.C. §§ 7470-7492. These statutory provisions and their implementing regulations at 40 C.F.R.

§ 52.21, collectively known as the PSD program, provide that if a major stationary source located in an attainment area is planning to make a major modification, then that source must obtain a PSD permit before beginning actual construction. *See* 40 C.F.R. § 52.21(i). To obtain this permit, the source must, among other things, undergo a technology review and apply Best Available Control Technology (BACT); perform a source impact analysis; perform an air quality analysis and modeling; submit appropriate information; and conduct additional impact analyses as required.

4. On September 16, 2008, EPA conditionally approved the State of Michigan's PSD program under 40 C.F.R. § 52.21, 73 Fed. Reg. 53366. On March 25, 2010, EPA fully approved Michigan's PSD SIP provisions, 75 Fed. Reg. 14,352. The Michigan PSD SIP provisions are codified at Michigan Admin. Code R. 336.2801 to 336.2830.

5. The PSD regulations appearing at Michigan Admin. Code R. 336.2801 to 336.2830 were incorporated into and part of the Michigan SIP at the time of the major modification at issue in this case, and they have been approved by EPA and are federally enforceable requirements. All citations to the PSD regulations herein refer to the provisions of Michigan SIP as applicable at the time of the Current Construction Activities described herein.

6. Michigan Admin. Code R. 336.2802(3) provides that no new major stationary source or major modification to which R 336.2810 to R 336.2818 apply shall begin actual construction without a permit to install issued under R 336.1201(1)(a) that states that the major stationary source or major modification will meet those requirements.

7. Michigan Admin. Code R. 336.2802(4) provides that this part applies to the construction of new major sources and major modifications to existing major sources in the following manner: (a) . . . a project is a major modification for a regulated new source pollutant if it causes both of the following types of emission increases: (i) significant emissions increase and (ii) significant net emission increase.

Non-attainment New Source Review

8. Part D of Title I of the Act, 42 U.S.C. §§ 7501-7515, sets forth provisions for New Source Review ("NSR") requirements for areas designated as being in non-attainment with the NAAQS standards. These provisions are referred to herein as the "Non-attainment NSR" program. The Non-attainment NSR program is intended to reduce emissions of air pollutants in areas that have not attained NAAQS so that the areas make progress towards meeting the NAAQS. Prior to the effective date of the 1990 Clean Air Act Amendments, P. Law 101-549, effective November 15, 1990, the Non-attainment NSR provisions were set forth at 42 U.S.C. §§ 7501-7508.

9. Under Section 172(c)(5) of the Non-attainment NSR provisions of the Act, 42 U.S.C. § 7502(c)(5), each state is required to adopt Non-attainment NSR SIP rules that include provisions to require permits that conform to the requirements of Section 173 of the Act, 42 U.S.C. § 7503, for the construction and operation of modified major stationary sources within non-attainment areas. Section 173 of the Act, in turn, sets forth a series of minimum requirements for the issuance of permits for major modifications to major stationary sources

within non-attainment areas. 42 U.S.C. § 7503.

10. Section 173(a) of the Act, 42 U.S.C. 7503(a), provides that construction and operating permits may be issued if, *inter alia*: "(a) sufficient offsetting emission reductions have been obtained to reduce existing emissions to the point where reasonable further progress towards meeting the national ambient air quality standards is maintained; and (b) the pollution controls to be employed will reduce emissions to the lowest achievable emission rate."

11. Under 40 C.F.R. Part 51, Appendix S, Emission Offset Interpretative Ruling, no person may undertake a major modification of an existing major stationary source in a non-attainment area without first obtaining a Non-attainment NSR permit.

12. Under Appendix S, a "major stationary source" of NO_x is one that emits or has the potential to emit 100 tons per year or more, and a "significant" net emissions increase of NO_x is one that results in increased emissions of 40 tons per year or more of this pollutant.

13. "Major modification" is defined by 40 C.F.R. Part 51, Appendix S, as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

FACTUAL BACKGROUND

14. DTE is a "person," as that term is defined in Section 302(e) of the Act, 42 U.S.C. § 7602(e).

15. From April 5, 2005, to the present, the Monroe power plant has been located in an area classified as non-attainment for fine particulates ($PM_{2.5}$).

16. At all times relevant to the NOV, the Monroe power plant has been located in an area that has been classified as attainment for SO_2 and ozone.

17. The Monroe power plant is a fossil fuel-fired electric utility steam generating station located in Monroe County, Michigan, and has the potential to emit more than 100 tons per year each of NO_x, SO_2, and particulate matter (PM). The plant consists of four cell burner boilers originally constructed in the early 1970s. Each boiler is connected to a turbine generator with a capacity of 750 to 795 megawatts (MWs).

18. The Monroe power plant is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour and is therefore a "major stationary source" within the meaning of 40 C.F.R. § 52.21(b)(1)(i)(a); and a "major emitting facility" within the meaning of Section 169(1) of the Act, 42 U.S.C. § 7479(1). *See also* Michigan Admin. Code R. 336.2801(cc).

19. On March 12, 2010, DTE sent a "Planned Outage Notification" letter ("Notification Letter") to the Michigan Department of Environmental Quality (now known as the MDNRE). The Notification Letter stated that DTE was going to begin a 12-week outage at

Monroe Unit 2 on or about March 13, 2010 and described the activities that would take place during the outage.

20. The construction activities that DTE commenced on or about March 13, 2010, include, but are not limited to the following work on the unit's boiler: replacement of economizer tubes; replacement of reheat pendants; and replacement of a section of waterwall tubes and burner cells.

21. EPA has calculated that the replacement projects identified in Paragrpah 20 are major modifications under the Clean Air Act and the Michigan implementing regulations, as they will result in projected emissions increases in excess of 40 TPY of NO_x and SO_2.

VIOLATIONS

Prevention of Significant Deterioration and Non-Attainment New Source Review

22. The physical change identified in the Paragraph 20, above, resulted in a significant net emissions increase, as defined at Michigan Admin. Code R. 336.2801 to 336.2830 and 40 C.F.R. Part 51, Appendix S, of SO_2, NO_x, $PM_{2.5}$, ozone and/or PM.

23. The physical change identified in Paragraph 20, above, constitutes a "major modification," as that term is defined at Michigan Admin. Code R. 336.2801 to 336.2830 and 40 C.F.R. Part 51, Appendix S.

24. For the physical change identified in Paragraph 20, above, DTE failed to obtain a PSD and/or non-attainment NSR permit as required by Michigan Admin. Code R. 336.2801 to 336.2830 and 40 C.F.R. Part 51, Appendix S.

25. DTE is in violation of PSD requirements, Section 165 of the Act, 42 U.S.C. § 7475, and Michigan Admin. Code R. 336.2801 to 336.2830 for constructing a major modification, as identified in Paragraph 20, above, to an existing major source at its Monroe power plant without applying for or obtaining a PSD permit, and operating the modified unit without installing BACT or going through PSD review, and installing appropriate emission control equipment in accordance with a BACT analysis.

26. DTE is in violation of non-attainment NSR requirements, Sections 171-193 of the Act, 42 U.S.C. §§ 7501-7515, and 40 C.F.R. Part 51, Appendix S, Emission Offset Interpretative Ruling, for constructing a major modification, as identified in Paragraph 20, above, to an existing major source at its Monroe power plant without applying for a permit, and operating the modified unit without installing LAER, obtaining Federally enforceable emission offsets at least as great as the new or modified source's emissions, certifying that all other major sources that it owns or operates are in compliance with the Act, and demonstrating that the benefits of the proposed source or modification significantly outweigh the environmental and social costs imposed as a result of its construction or modification.

ENFORCEMENT AUTHORITY

27. Section 113(a)(1) of the Act, 42 U.S.C. § 7413(a)(1), provides that at any time after the expiration of 30 days following the date of the issuance of a Notice of Violation, the Administrator may, without regard to the period of violation, issue an order requiring compliance with the requirements of the state implementation plan or permit, issue an administrative penalty order pursuant to Section 113(d), or bring a civil action pursuant to Section 113(b) for injunctive relief and/or civil penalties.

28. Section 113(a)(3) of the Act, 42 U.S.C. § 7413(a)(3), provides in part that if the Administrator finds that a person has violated, or is in violation of any requirement or prohibition of any rule…promulgated…under…[Title I of the Act], the Administrator may issue an administrative penalty order under Section 113(d), issue an order requiring compliance with such requirement or prohibition, or bring a civil action pursuant to Section 113(b) for injunctive relief and/or civil penalties.

29. Section 113(b) of the Act, 42 U.S.C. § 7413(b), authorizes the Administrator to initiate a judicial enforcement action for a permanent or temporary injunction, and/or for a civil penalty of up to $25,000 per day for each violation occurring on or before January 30, 1997; up to $27,500 per day for each such violation occurring on or after January 31, 1997, and up to and including March 15, 2004; up to $32,500 per day for each such violation occurring on or after March 16, 2004 through January 12, 2009; and up to $37,500 per day for each such violation occurring on or after January 13, 2009, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701, 40 C.F.R. § 19.4, and 74 Fed. Reg. 626 (Jan. 7, 2009), against any person whenever such person has violated, or is in violation of, *inter alia,* the requirements or prohibitions described in the preceding paragraphs.

Dated 6/4/10

Phillip A. Brooks
Director
Air Enforcement Division

CERTIFICATE OF MAILING

I, Ilana Saltzbart, certify that I sent a Notice of Violation and Finding of Violation, EPA-HQ-2010-MI-1, by Certified Mail, Return Receipt Requested, to:

Skiles W. Boyd, Director of Environmental Management
Detroit Edison Company
2000 Second Ave.
Detroit, MI 48226-1279

I also certify that I sent copies of the Notice of Violation and Finding of Violation by Certified Mail, Return Receipt Requested, to:

Michael Solo, Esq.
DTE Energy
One Energy Plaza
Detroit, MI 48226-1279

Thomas Hess, Unit Supervisor
Compliance and Enforcement Section
Michigan Department of Natural Resources and Environment
Air Quality Division
P.O. Box 30260
Lansing, Michigan 48909

Teresa Seidel, District Supervisor
Michigan Department of Natural Resources and Environment
Southeast Michigan District Office
27700 Donald Court
Warren, Michigan 48092-2793

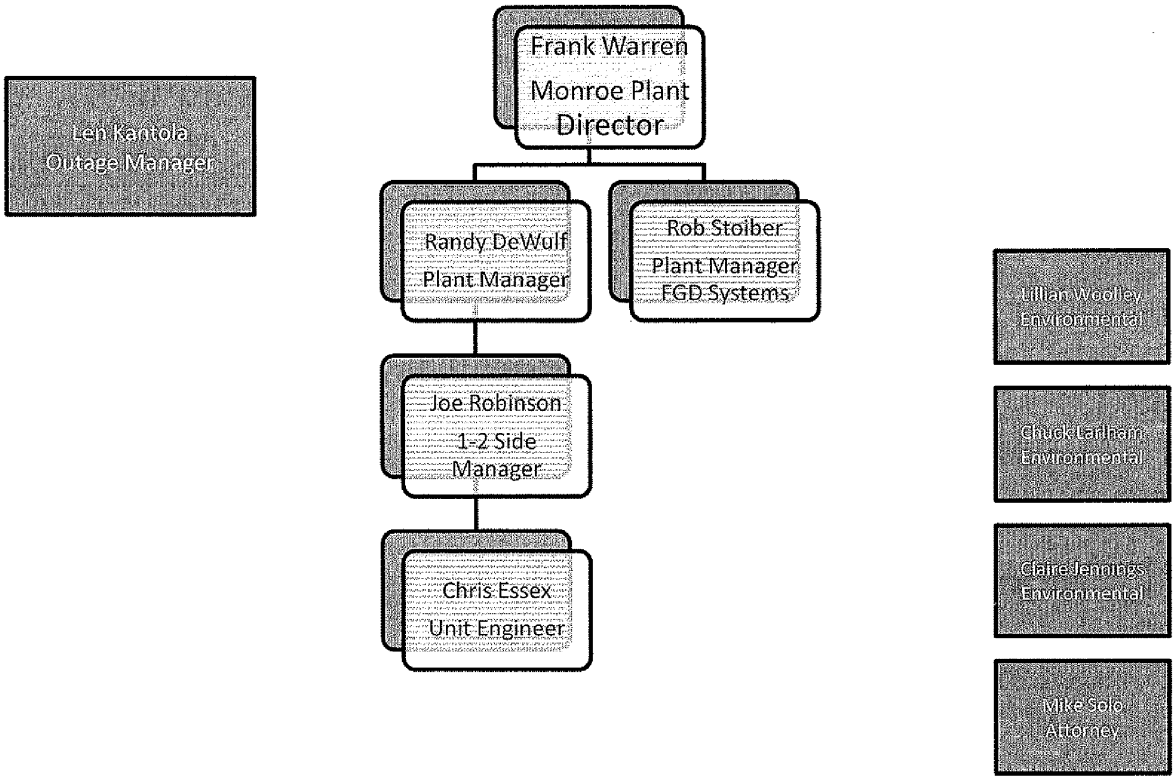
Jack Larsen, District Supervisor
Michigan Department of Natural Resources and Environment
State Office Building, 4th Floor
301 E. Louis B. Glick Highway
Jackson, Michigan 49201

On the 4th day of June, 2010

CERTIFIED MAIL RECEIPT NUMBER: 7008 2810 0001 0214 1544

Exhibit 2-F
FILED UNDER SEAL

Monroe Power Plant Environmental Meeting



1. Introduction

- The Unit 2 Periodic Outage is scheduled to begin March 13 and end June 9, 2010.
- The next MONPP Unit 2 Mid Cycle Periodic Outage is scheduled for 2013.

2. Goals

Description	Goal
1. Lost Work Day Cases (Count)	0
2. OSHA Recordable Injury Rate (#/200,000 man-hours)	< 1.7
3. Incidents involving improper handling of Asbestos	0
4. Reportable Spills & Opacity Exceedances	0
5. Startup Opacity Exceedances	< 3
6. Outage Duration	< 88.3 Days
7. O&M Budget (Direct Incremental O&M)	$11,355,000
8. Small Capital Budget	$2,107,751
9. Large Capital Budget	$51,223,348
10.Original Work Scope Completion (%)	> 98 %

3. Capital Project Status

PMP	Description	Contacts	Design Issue	Work Orders	Parts Receipt	Contract Services	Schedule Status	PAT 2 Status?	Target Cost
0705	Replace Reheat Pendants [GL I.000022.0073.xxx] [Cost Cap 30008056]	Proj Mgr: Phil Hinz Planner: Jerry Brake Scheduler: Dan Koppenaal Craft: WGI	Ready	Ready	Ready	Ready	Ready	Ready	14,500,000
2758	Expansion Joint Replacement (10 total) (AH gas side) [GL I.000022.0091.xxx] [Cost Cap 30617727]	Proj Mgr: Jim Polsgrove Proj Eng: Tom Norfork Planner: Jerry Brake Scheduler: Dan Koppenaal Craft: WGI	Ready	Ready	Ready	Ready	Ready	Ready	800,000
2959	Install Static Exciter [GL I.000022.0052.xxx] [Cost Cap 29817145]	Proj Mgr: Mark Kimmel Planner: Art Parrack Scheduler: S. Romanowski Supervisor: Rhonda Bond Craft: Motor City Elect, I&C, Elect, PERT	Ready	Ready	Ready	Ready	Ready	Ready	6,394,600
4218	Generator Lead Box Replacement [GL I.000022.0079.xxx] [Cost Cap 29033949]	Proj Mgr: Mark Kimmel Planner: John LaCasse Scheduler: S. Romanowski Supervisor: Rhonda Bond Craft: Duke & Duke	Ready	Ready	Ready	Ready	Ready	Ready	3,509,995
5240	Replace Economizer Tubes [GL I.000022.0081.xxx] [Cost Cap 29359396]	Proj Mgr: Phil Hinz Planner: Jerry Brake Scheduler: Dan Koppenaal Craft: WGI, I&C	Ready	Ready	Ready	Ready	Ready	Ready	14,500,000
5524	Generator Rotor Rewind [GL I.000022.0082.xxx] [Cost Cap 29825913]	Proj Mgr: Mark Kimmel Planner: John LaCasse Scheduler: S. Romanowski Supervisor: Dominic Mento Craft: Turbine Team, I&C, Motor City Elect	Ready	Ready	Ready	Ready	Ready	Ready	3,530,753
5637	210 Valve Replacement [GL I.000022.0085.xxx] [Cost Cap 29665358]	Proj Mgr: Jim Polsgrove Planner: Jerry Brake Scheduler: S. Romanowski Craft: DTE, Elect, I&C	Ready	Ready	Ready	Ready	Ready	Feb 17	347,000
5680	4160v Cable Replacement [GL I.000022.0089.xxx] [Cost Cap 30478451]	Proj Mgr: Jim Polsgrove PE: Tom Norfolk Planner: Jerry Brake Scheduler: S. Romanowski Craft: Conti Elect, PERT	Ready	Ready	Ready	Ready	Ready	Ready	678,000
5685	Waterwall Panel Replacement [GL I.000022.0087.xxx] [Cost Cap 30399298]	Proj Mgr: Phil Hinz Planner: Jerry Brake Sch: Dan Koppenaal Craft: WGI	Ready	Ready	Ready	Ready	Ready	Ready	6,022,000
6354	Replace SS Trf #62 [GL I.000022.0088.xxx] [Cost Cap 30478977]	Proj Mgr: Jim Polsgrove PE: Elaine Harrison Planner: Jerry Brake Scheduler: S. Romanowski Craft: Dist Ops, PERT, I&C	Ready	Ready	Ready	Ready	Ready	Ready	941,000
								Total Large Cap Budget	51,223,348

PMP	Description	Contacts	Design Issue	Work Orders	Parts Receipt	Contract Services	Schedule Status	Target Cost ($)
3071	Install Boiler Feed Pump TSI [I.000171.0205.0001] [Cost Cap 30777268]	Proj Mgr: Reid Rodgers Planner: Art Parrack Sch: Sean Romanowski Craft: Elect, I&C,PERT	Ready	Ready	Ready	Ready	Ready	283,000
3422	Replace Coal Silos 2, 3 & 5 [GL I.000022.0093.xxx] [Cost Cap 30815048]	Proj Mgr: Al Thorn Planner: Al Thorn Sch: Sean Romanowski Craft: RMF	Ready	Ready	Ready	Ready	Ready	545,000
3896	Replace 130/260v Battery Chargers [GL I.000171.0234.xxx] [Cost Cap 30885910]	Proj Mgr: Lee Miera Planner: Art Parrack Sch: Sean Romanowski Craft: Elect, PERT	Ready	Ready	June 1	Ready	Ready	49,751
3920	Rebuild SBFP [I.000171.0210.0001] [Cost Cap 30801402]	Proj Mgr: Mark Kimmel Planner: John Lacasse Sch: Sean Romanowski Craft: Turbine Team	Ready	Ready	Ready	Ready	Ready	315,000
6579	4160 Volt Circuit Breaker Upgrades (9) [I.000171.0206.0001] [Cost Cap 30772796]	Proj Mgr: Lee Miera Planner: Art Parrack Sch: Sean Romanowski Craft: Elect	Ready	Ready	Ready	Ready	Ready	90,000
6655	Pump Replacement-Contingency [I-000171.00143.0004] [Cost Cap 30772747]	Proj Mgr: Jim Drotar Planner: Randy Spaulding Scheduler: Larry Hailey Craft: DTE	Ready	Ready	Ready	Ready	NA	25,000
6656	Motor Replacement – Contingency [I.000171.00171.0004] [Cost Cap 30772764]	Proj Mgr: Jim Drotar Planner: Dennis Liska Scheduler: Larry Hailey Craft: DTE	Ready	Ready	Ready	Ready	NA	25,000
6657	Valve Replacement [I.000171.0170.0004] [Cost Cap 30772740]	Proj Mgr: Jim Drotar Planner: Randy Spaulding Scheduler: Larry Hailey Craft: DTE, WGI	Ready	Ready	Ready	Ready	Ready	550,000
6658	Asbestos Removal [I.000171.0207.0003] [Cost Cap 30778455]	Proj Mgr: Jim Drotar Planner: Randy Spaulding Sch: Sean Romanowski Craft: D2	Ready	Ready	Ready	Ready	Ready	175,000
6659	Lead Abatement [I.000171.0208.0003] [Cost Cap 30778572]	Proj Mgr: Jim Drotar Planner: Randy Spaulding Sch: Sean Romanowski Craft: D2	Ready	Ready	Ready	Ready	Ready	50,000
							Total Small Capital Budget	2,107,751

DTE Energy

Appropriation Request
Summary Sheet

Project Name:	Monroe 2 Reheater	Capital Budget / Project #: PMP 705	10/28/2009
Business Segment:	Energy Resources	Project Type:	Reliability
Business Unit:	Fossil Generation		
Executive Sponsor:	Paul Fessler	In Approved Project Budget? (Y/N):	Y
Project Start Date:	January 2008	In-Service Date:	Spring 2010
Post Investment Evaluation Date:			

Current Approval Request	$12,900	Previous Request(s):	$4,400
		Total Project	$17,300

Financial Summary ($000s)

	Prior Years	2009	2010	2011	2012	2013	Beyond	Project Total
Current Capital Approval Request	$2,500	$1,900	$12,900	$0	$0	$0	$0	$17,300
								Average
Operating After-Tax Cash Flow (Regulated Model)	$0	($4,100)	($11,800)	$1,900	$1,900	$1,800	$1,700	($1,400)
Net Income (Regulated Model)	$0	$100	$300	$900	$800	$800	$800	$600

Hurdle Rate	IRR	NPV	Payback	First 5 Yrs Avg. Net Income
7.50%	7.5%	$0	9.90	$600

Project Description and Approval Discussion

This project is the replacement of the Monroe Power Plant Unit 2 Reheater inlet and outlet pendants during the Spring 2010 periodic outage. Monroe Unit 2 is the second of a four unit reheater replacement strategy at Monroe. Monroe Unit 1 was successfully installed in May 2009. Materials for this project have already been approved for procurement (2008).

Major Risk and Risk Mitigants

There is a potential risk of boilermaker weld quality and productivity due to a decreasing labor pool. Lessons learned from the successful installation at Monroe 1 will be used to mitigate any effects of these challenges.

Corporate Staff Evaluations Signatures		Date	Final Approval Signatures	Date
☐ Corp. Development			~~Business Leader~~ Chief Operating Officer	
☐ Corporate Accounting				10/26/09
☐ Controller			Executive Sponsor	
☐ Corporate Tax				10/27/09
☐ Corporate Finance			~~Chief Operating Officer~~ Business Unit Leader	
☐ Legal				11-5-09
☐ Regulatory Affairs			Chief Financial Officer	
☐ Risk Management				11/9/09
☐ "LES" Team			Chief Executive Officer	
☐ Other				

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Version: AR 7/06

DTE Energy

Appropriation Request
Summary Sheet

Project Name:	Monroe 2 Reheater	Capital Budget / Project #: PMP 705	10/28/2009
Business Segment:	Energy Resources	Project Type:	Reliability
Business Unit:	Fossil Generation		
Executive Sponsor:	Paul Fessler	In Approved Project Budget? (Y/N):	Y
Project Start Date:	January 2008	In-Service Date:	Spring 2010
Post Investment Evaluation Date:			

Current Approval Request	$12,900	Previous Request(s):	$4,400
		Total Project	$17,300

Financial Summary ($000s)

	Prior Years	2009	2010	2011	2012	2013	Beyond	Project Total
Current Capital Approval Request	$2,500	$1,900	$12,900	$0	$0	$0	$0	$17,300
								Average
Operating After-Tax Cash Flow (Regulated Model)	$0	($4,100)	($11,800)	$1,900	$1,900	$1,800	$1,700	($1,400)
Net Income (Regulated Model)	$0	$100	$300	$900	$800	$800	$800	$600

Hurdle Rate	IRR	NPV	Payback	First 5 Yrs Avg. Net Income
7.50%	7.5%	$0	9.90	$600

Project Description and Approval Discussion

This project is the replacement of the Monroe Power Plant Unit 2 Reheater inlet and outlet pendants during the Spring 2010 periodic outage. Monroe Unit 2 is the second of a four unit reheater replacement strategy at Monroe. Monroe Unit 1 was successfully installed in May 2009. Materials for this project have already been approved for procurement (2008).

Major Risk and Risk Mitigants

There is a potential risk of boilermaker weld quality and productivity due to a decreasing labor pool. Lessons learned from the successful installation at Monroe 1 will be used to mitigate any effects of these challenges.

Corporate Staff Evaluations Signatures		Date
☒ Corp. Development		10-26-09
☒ Corporate Accounting		10-22-09
☒ Controller		10-22-09
☒ Corporate Tax		10-22-09
☒ Corporate Finance		10/21/09
☒ Legal		10/23/09
☒ Regulatory Affairs		10/21/09
☒ Risk Management		10/21/09
☐ "LES" Team		N/A
☒ Other		10/22/09

Final Approval Signatures	
SBU Leader	Date
Executive Sponsor	Date
Chief Operating Officer	Date
Chief Financial Officer	Date
Chief Executive Officer	Date

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Version: AR 7/09

DTE Energy
Detroit Edison

FOSSIL GENERATION PAT REVIEW REQUEST FORM - ALLPP - FM - 0013

PAT AT Agenda Date:	
PMP Project ID:	705
PAT LVL/REV:	PAT 2, REV 2
Outage Related?	Yes
Outage Start Date:	Mar-10
Project Start Date:	Oct-09
Investment Reason:	6 Reliability

Project Site:	MONPP
Unit:	2
Projected I/S Date (EST):	6/1/2010
Current IRR:	30%
SAP Profit Center #	
WBS Element:	I-000022-0073
Project Type/Systems:	Boiler

Scope Change [X] New Revision
Schedule Change Release of Contingency

Project Title: Unit 2 Reheat Pendant Replacement

PMP Problem Description & Project Objective *(Project deliverables? Sum benefits-attach extra sheets if required):*
The boiler tubes in the Reheat Pendants are failing. Unit 2 has experienced reheater pendant failures resulting in forced outages. Analysis done by the Boiler Tube Task Force predicts more frequent failures in the future. Objective would be to improve the reliability of Unit 2 by replacing the secondary reheater inlet and outlet pendants during the next Unit 2 major periodic outage.

Brief Project Scope Summary *(Summarize products & services provided)*
Remove and replace the front and rear sections of the inlet and outlet pendants. Upgrade materials to account for current and future boiler operating temperature conditions.

Reason for Submittal *(Categorize requested dollar amount changes, e.g., engineering, long lead procurement, etc. also state whether request is for PAT 1 or 2 and explain any budget at completion (BAC) benefits or IRR changes):*
PAT 2 Rev. 2 required to recover funds displaced during estimate labor tabulation and repair of AFUDC calculation in estimate template.

	Prior Years	2009	2010	2011
Previously Approved PAT:	$2,520,491	$1,793,712	$10,850,506	$0
PAT Change Request:	$0	$0	$606,282	$0
Current PAT Request:	$2,520,491	$1,793,712	$11,456,788	$0

	Current Forecast				Forecast Changes				Revised Forecast			
	Prior Years	2009	2010	Future Years	Prior Years	2009	2010	Future Years	Prior Years	2009	2010	Project Total(EAC)
Material + Burden	$2,520,491	$1,300,000	$846,701	$0	$0	$0	$0	$0	$2,520,491	$1,300,000	$846,701	$4,667,192
Labor-DTE	$0	$35,640	$936,862	$0	$0	$0	$0	$0	$0	$35,640	$936,862	$972,502
Labor-Contract	$0	$319,342	$7,484,623	$0	$0	$0	$410,000	$0	$0	$319,342	$7,894,623	$8,213,965
ENG-DTE	$0	$27,500	$12,740	$0	$0	$0	$0	$0	$0	$27,500	$12,740	$40,240
ENG-Contract	$0	$0	$65,000	$0	$0	$0	$0	$0	$0	$0	$65,000	$65,000
Overhead,AFUDC,A&G	$0	$50,528	$610,085	$0	$0	$0	$296,282	$0	$0	$50,528	$906,347	$956,875
Fos Gen Overhead	$0	$60,702	$894,515	$0	$0	$0	-$100,000	$0	$0	$60,702	$794,515	$855,217
MEP Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total	$2,520,491	$1,793,712	$10,850,506	$0	$0	$0	$606,282	$0	$2,520,491	$1,793,712	$11,456,788	$15,770,991
Contingency	$0	$0	$1,335,291	$0	$0	$0	-$606,282	$0	$0	$0	$729,009	$729,009
TOTAL	$2,520,491	$1,793,712	$12,185,797	$0	$0	$0	$0	$0	$2,520,491	$1,793,712	$12,185,797	$16,500,000

FG Investment Planning Representative:	1204050
Project Engineer:	Elaine Harrison
Project Manager:	Phi Hinz

DISPOSITION:
- [ ] Approved with Contingency
- [ ] Approved without Contingency
- [ ] Deferred Until:
- [ ] Rejected
- [ ] Request to be presented to PAT

PAT Chairman: R E Palmer UCC AR on file Date: 4/21/2010

NOTE to Requester: Previous Approved PAT and Current Forecast numbers must agree with Current PAT Request and Revised Forecast, respectively, shown on prior PAT Request form. [REV 0 - 04/08/09]

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DTE Energy

Appropriation Request

Summary Sheet

Project Name:	Monroe 2 Economizer	Capital Budget / Project #: PMP 5240	2/26/2009
Business Segment:	Energy Resources	Project Type:	Reliability
Business Unit:	Fossil Generation		
Executive Sponsor:	Paul Fessler	In Approved Project Budget? (Y/N):	Y
Project Start Date:	Jan 2009	In-Service Date:	Spring 2010
Post Investment Evaluation Date:			

Current Approval Request	$16,800	Previous Request(s):	
		Total Project	$16,800

Financial Summary ($000s)

	Prior Years	2009	2010	2011	2012	2013	Beyond	Project Total
Current Capital Approval Request	$0	$2,200	$14,600	$0	$0	$0	$0	$16,800
								Average
Operating After-Tax Cash Flow (Regulated Model)	$0	($2,200)	($13,400)	$1,900	$1,800	$1,800	$1,700	($1,400)
Net Income (Regulated Model)	$0	$0	$250	$860	$820	$780	$740	$500

Hurdle Rate	IRR	NPV	Payback	First 5 Yrs Avg. Net Income
7.50%	7.5%	$0	9.80	$600

Project Description and Approval Discussion

This project is to remove and replace the economizer on Unit 2 at Monroe Power Plant. With this project, the plan is to address the lost availability due to economizer tube leaks and improve reliability. The replacement will reduce future outages that provide substantial benefits to the customer --28% of the projects 35% competitive IRR. The scope of this project is to replace 323 tube elements with new material.

Major Risk and Risk Mitigants

Items of risk include material inflation and labor costs. This risk will be addressed through executing a competitive bid process and take advantage of low material prices.

Corporate Staff Evaluations Signatures		Date
☒ Corp. Development		2-24-09
☒ Corporate Accounting		2-20/09
☒ Controller		2/24/2008
☐ Corporate Tax		2/24/2009
☒ Corporate Finance		2/19/08
☒ Legal *		2/19/09
☐ Regulatory Affairs		2/19/09
☒ Risk Management		2/19/09
☐ "LES" Team-Environmental		2/23/09
☐ Other Purchasing		2/23/09

Final Approval Signatures		Date
SBU Leader		2/16/09
Executive Sponsor		2/17/09
Chief Operating Officer		
Chief Financial Officer		2-26-09
Chief Executive Officer		2/26/09

* TO DATE LEGAL HAS COMMENTED ON THE EQUIPMENT SPEC.

Version: AR 7/06

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FOSSIL GENERATION PAT REVIEW REQUEST FORM

PAT AT Agenda Date:	NA
PMP Project ID:	5240
PAT LVL/REV:	PAT 2, REV 5

Scope Change [X] New Revision
Schedule Change Release of Contingency

Project Title: MONPP Unit 2 Economizer Replacement

Project Site:	MONPP	Outage Related?	Yes
Unit:	2	Outage Start Date:	March 2010
Projected I/S Date (EST):	Jul-10	Project Start Date:	Nov-09
Current IRR:	35%	Investment Reason:	6 Reliability
SAP Profit Center #	0202R		
WBS Element:	I-000022-0081		
Project Type/Systems:	02 Boiler		

PMP Problem Description & Project Objective *(Project deliverables? Sum benefits-attach extra sheets if required):*
Description: The Unit 2 economizer tubes have been damaged during lengthy service in an erosive environment. Tube failures and forced outages are occurring at an increasing rate.
Objective: Operation of the unit without forced outages caused by economizer tube failures.

Brief Project Scope Summary *(Summarize products & services provided)*
Design an economizer which is less susceptible to erosion and which meets performance criteria set by DTE. Fabricate new economizer. Remove existing Unit 2 economizer. Install new economizer.

Reason for Submittal *(Categorize requested dollar amount changes, e.g., engineering, long lead procurement, etc. also state whether request is for PAT 1 or 2 and explain any budget at completion (BAC) benefits or IRR changes):*
PAT 2 Rev 5 attempt to true up 2009 spending and to reflect field estimate to current construction costs

	Prior Years	2009	2010	2011
Previously Approved PAT:	$0	$4,302,309	$8,729,541	$0
PAT Change Request:	$0	$41,364	$3,051,803	$0
Current PAT Request:	$0	$4,343,673	$11,781,344	$0

	Current Forecast				Forecast Changes				Revised Forecast			
	Prior Years	2009	2010	Future Years	Prior Years	2009	2010	Future Years	2009	2010	Future Years	Project Total(EAC)
Material + Burden	$0	$3,674,909	$2,088,000	$0	$0	$0	-$1,339,145	$0	$3,674,909	$748,855	$0	$4,423,764
Labor-DTE	$0	$92,000	$580,000	$0	$0	$0	$187,030	$0	$92,000	$767,030	$0	$859,030
Labor-Contract	$0	$63,000	$6,337,000	$0	$0	$20,000	$2,621,595	$0	$83,000	$8,958,595	$0	$9,041,595
ENG-DTE	$0	$50,750	$40,000	$0	$0	$0	-$79,830	$0	$50,750	-$39,830	$0	$10,920
ENG-Contract	$0	$110,000	$150,000	$0	$0	$0	$72,300	$0	$110,000	$222,300	$0	$332,300
Overhead,AFUDC,A&G	$0	$155,650	$856,850	$0	$0	$21,364	-$510,325	$0	$177,014	$346,525	$0	$523,539
Fos Gen Overhead	$0	$156,000	$430,000	$0	$0	$0	$347,869	$0	$156,000	$777,869	$0	$933,869
MEP Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total	$0	$4,302,309	$10,481,850	$0	$0	$41,364	$1,299,494	$0	$4,343,673	$11,781,344	$0	$16,125,017
Contingency	$0	$0	$3,768,150	$0	$0	$0	-$3,093,167	$0	$0	$674,983	$0	$674,983
TOTAL	$0	$4,302,309	$14,250,000	$0	$0	$41,364	-$1,793,673	$0	$4,343,673	$12,456,327	$0	$16,800,000

FG Investment Planning Representative:	W. Dugliss
Project Engineer:	W. Dugliss
Project Manager:	P. Hinz
PAT Chairman:	Steven Plam

DISPOSITION:
- [ ] Approved with Contingency
- [X] Approved without Contingency
- [ ] Deferred Until: _____
- [ ] Rejected
- [ ] Request to be presented to PAT

Date: 2/5/10

NOTE to Requester: Previous Approved PAT and Current Forecast numbers must agree with Current PAT Request and Revised Forecast, respectively, shown on prior PAT Request form.

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FOSSIL GENERATION PAT REVIEW REQUEST FORM - ALLPP - FM - 0013

PAT AT Agenda Date:	
PMP Project ID:	5685
PAT LVL/REV:	PAT 2, REV 0

Scope Change [X] New Revision
Schedule Change Release of Contingency

Project Title: MONPP Unit 2 Water Wall Replacement

Project Site:	MONPP	Outage Related?	Yes
Unit:	2	Outage Start Date:	Mar-10
Projected I/S Date (EST):	15-Jun-10	Project Start Date:	Feb-10
Current IRR:	37 % - 51 %	Investment Reason:	6 Reliability
SAP Profit Center #			
WBS Element:	1 - 000022-0087		
Project Type/Systems:	Boiler Steam Generator		

PMP Problem Description & Project Objective *(Project deliverables? Sum benefits-attach extra sheets if required):*

Replace water wall surface internal to the Unit 2 Boiler to improve reliability due to water wall tube failure from reduced wall thickness of Boiler Tubes.

- Water wall tube panels. = to 22 Full size and 8 (1/2 size) (1528 sq. ft.)
- Bent WW Tubes around the Division wall Penetrations. (East and West wall) (47 sq. ft.)
- Slope Nose Tubes – 5 tubes. (4 sq. ft.)
- 3 Burner Cells to be replaced with refractory box. (201 sq. ft.)
- 4 Soot blower openings. (6 sq. ft.)
- 10 Division Wall Tube Replacements = 40 feet with bends, through penetration wall sections, and into the wind box. (56 sq. ft.)

Brief Project Scope Summary *(Summarize products & services provided)*

Replace damaged water wall panels with new tubes which are clad with a corrosion resistant alloy.

Reason for Submittal *(Categorize requested dollar amount changes, e.g., engineering, long lead procurement, etc. also state whether request is for PAT 1 or 2 and explain any budget at completion (BAC) benefits or IRR changes):*

PAT 2 required to start the construction phase of project True up 2009 spending.

	Prior Years	2010	2011	2012
Previously Approved PAT:	$29,000	$0	$0	$0
PAT Change Request:	-$27,280	$6,022,580	$0	$0
Current PAT Request:	$1,720	$6,022,580	$0	$0

	Current Forecast				Forecast Changes				Revised Forecast			
	Prior Years	2010	2011	Future Years	Prior Years	2010	2011	Future Years	Prior Years	2010	Future Years	Project Total(EAC)
Material + Burden	$0	$1,070,000	$0	$0		$301,032	$0	$0	$0	$1,371,032	$0	$1,371,032
Labor-DTE	$0	$40,000	$0	$0	-$27,280	$409,435	$0	$0	-$27,280	$449,435	$0	$422,155
Labor-Contract	$0	$3,200,000	$0	$0	$0	-$102,214	$0	$0	$0	$3,097,786	$0	$3,097,786
ENG-DTE	$10,000	$100,000	$0	$0	$0	-$50,000	$0	$0	$10,000	$50,000	$0	$60,000
ENG-Contract	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Overhead,AFUDC,A&G	$0	$744,000	$0	$0	$0	-$40,873	$0	$0	$0	$703,127	$0	$703,127
Fos Gen Overhead	$19,000	$305,000	$0	$0	$0	$46,200	$0	$0	$19,000	$351,200	$0	$370,200
MEP Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total	$29,000	$5,459,000	$0	$0	-$27,280	$563,580	$0	$0	$1,720	$6,022,580	$0	$6,024,300
Contingency	$0	$495,000	$0	$0	$0	-$264,200	$0	$0	$0	$230,800	$0	$230,800
TOTAL	$29,000	$5,954,000	$0	$0	-$27,280	$299,380	$0	$0	$1,720	$6,253,380	$0	$6,255,100

FG Investment Planning Representative:	
Project Engineer:	E. Harrison
Project Manager:	P Hinz
PAT Chairman:	

DISPOSITION:

- [ ] Approved with Contingency
- [X] Approved without Contingency
- [ ] Deferred Until: _____
- [ ] Rejected
- [ ] Request to be presented to PAT

Date: 1/15/2010

NOTE to Requester: Previous Approved PAT and Current Forecast numbers must agree with Current PAT Request, and Revised Forecast, respectively, shown on prior PAT Request form. [REV 0 - 04/08/09]

CONFIDENTIAL

Report Id: P3MOUTGD

EVENT HISTORY DETAIL REPORT

Date : 06/02/2010 15:13

For Period: 08/01/2008 00:00 --- 06/02/2010 12:00

Plant MONPP

Unit 2

MPAC Id	MW Loss	Start Date	End Date	Fuel Loss	Fuel Gain	Gain Type	Fuel loss mwwks	Hours	Weeks	Nerc Description	Failure	Event Type
Turbine - General	0	04/07/08 00:00	10/23/08 10:00				0.00	2002.00	0.00	HIGH CIRCULATING WATER TEMPERATURE	Back pressure	NC
Boiler - General	15	06/02/08 10:30	08/04/08 08:55				0.00	80.92	7.22	HP HEATER TUBE LEAKS	Leaks	D1
Boiler - General	20	07/22/08 07:11	08/15/08 06:57				0.00	342.95	40.83	OTHER FLUE GAS PROBLEMS	Plugged	D1
MTG - HP Turbine	10	07/28/08 00:01	08/06/08 01:00				0.00	121.00	7.20	HP TURBINE BUCKET OR BLADE FOULING	Erosion - cause unknown	D1
Boiler - General	65	07/28/08 16:26	08/15/08 06:57				0.00	342.95	132.69	FEEDWATER CONTROLS	Leaks	D1
Boiler - General	660	07/31/08 23:57	08/03/08 20:35				0.00	68.58	269.43	ECONOMIZER LEAKS	Leaks	U1
N. FD Fan	190	08/04/08 04:22	08/15/08 06:57				0.00	266.58	301.49	FORCED DRAFT FAN DRIVES(OTHER THAN MOTOR)	Broken	D1
Coal Mill 6	0	08/04/08 23:33	08/16/08 17:09	0			0.00	281.60	0.00	PULVERIZER INSPECTION	Inspection	NC
MTG - HP Turbine	10	08/06/08 01:01	08/16/08 08:30				0.00	247.48	14.73	HP TURBINE BUCKET OR BLADE FOULING	Erosion - cause unknown	NC
Boiler - General	485	08/09/08 01:00	08/16/08 15:08				0.00	182.13	525.80	OTHER FLUE GAS PROBLEMS	Plugged	U1
MTG - HP Turbine	10	08/16/08 08:31	08/17/08 06:00				0.00	21.48	1.28	HP TURBINE BUCKET OR BLADE FOULING	Erosion - cause unknown	D1
MTG - HP Turbine	10	08/17/08 06:01	09/10/08 11:00				0.00	580.98	34.58	HP TURBINE BUCKET OR BLADE FOULING	Erosion - cause unknown	NC
Boiler - General	275	08/18/08 01:00	08/18/08 04:38				0.00	3.63	5.95	CONDENSATE POLISHING AND FILTERING SYSTEMS	Plugged	NC
Turbine - General	395	08/19/08 01:00	08/19/08 05:41				0.00	4.68	11.01	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Coal Mill 4	70	08/25/08 15:03	08/26/08 15:15	70			10.08	24.20	10.08	PULVERIZER FEEDERS	Broken	D1
Boiler - General	775	08/27/08 22:00	09/01/08 17:00				0.00	115.00	530.51	ECONOMIZER LEAKS	Leaks	U1
MTG - HP Turbine	10	09/10/08 11:01	09/10/08 17:00				0.00	5.98	0.36	HP TURBINE BUCKET OR BLADE FOULING	Erosion - cause unknown	D1
MTG - HP Turbine	10	09/10/08 17:01	10/19/08 17:00				0.00	935.98	55.71	HP TURBINE BUCKET OR BLADE FOULING	Erosion - cause unknown	NC
Coal Mill 6	0	09/17/08 08:00	09/17/08 09:52	20	20	2OIL	0.22	1.87	0.00	PULVERIZER MILLS	Cleaning	D1
Turbine - General	400	09/18/08 00:30	09/18/08 03:49				0.00	3.32	7.90	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Coal Mill 4	0	09/23/08 12:01	09/23/08 16:38	0			0.00	4.62	0.00	PULVERIZER FEEDER MOTOR	Failure	D1
Coal Mill 5	0	09/24/08 01:00	10/06/08 03:22	0			0.00	290.37	0.00	PULVERIZER MILLS	Inspection	D1
S. Boiler Feed Pump	240	09/27/08 01:52	09/27/08 05:42				0.00	3.83	5.48	FEEDWATER PUMP	Unknown-Investigation Underway	D1
Boiler - General	0	09/29/08 01:00	09/29/08 02:15				0.00	1.25	0.00	CONDENSER TUBE AND WATER BOX CLEANING	Back pressure	NC
Turbine - General	395	10/11/08 00:31	10/11/08 07:46				0.00	7.25	17.05	CONDENSER TUBE SHEET FOULING	Plugged	NC
MTG - HP Turbine	10	10/19/08 17:01	10/26/08 04:00				0.00	154.98	9.23	HP TURBINE BUCKET OR BLADE FOULING	Erosion - cause unknown	D1
Boiler - General	0	10/21/08 05:19	10/23/08 10:02				0.00	52.72	0.00	INDUCED DRAFT FANS	Plugged	NC

EVENT HISTORY DETAIL REPORT

For Period: 08/01/2008 00:00 --- 06/02/2010 12:00

Plant MONPP
Unit 2

MPAC Id	MW Loss	Start Date	End Date	Fuel Loss	Fuel Gain	Gain Type	Fuel loss mwwks	Hours	Weeks	Nerc Description	Failure	Event Type
Coal Mill 7	0	10/21/08 17:23	10/21/08 22:00				0.00	4.62	0.00	PULVERIZER MILLS	Broken	D1
Turbine - General	0	10/23/08 10:00	10/30/08 05:07				0.00	163.12	0.00	HIGH CIRCULATING WATER TEMPERATURE	Back pressure	NC
Boiler - General	15	10/25/08 05:53	10/27/08 04:06				0.00	46.22	4.13	FIRST REHEATER SLAGGUBG/FOULING	Restricted	D1
MTG - HP Turbine	10	10/26/08 04:01	10/29/08 01:00				0.00	68.98	4.11	HP TURBINE BUCKET OR BLADE FOULING	Erosion - cause unknown	NC
Turbine - General	145	10/27/08 04:00	10/27/08 05:05				0.00	1.08	0.94	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	D1
Turbine - General	775	10/27/08 05:05	10/27/08 12:41				0.00	7.60	35.06	OTHER FEEDWATER PUMP PROBLEMS	Instrumentation	U1
MTG - HP Turbine	10	10/29/08 01:01	10/30/08 01:00				0.00	23.98	1.43	HP TURBINE BUCKET OR BLADE FOULING	Erosion - cause unknown	D1
MTG - Generator	0	10/29/08 08:00	10/29/08 15:03				0.00	7.05	0.00	GENERATOR ROTOR WINDINGS	Testing	NC
Coal Mill 7	0	11/02/08 20:00	11/12/08 17:21				0.00	237.35	0.00	PULVERIZER INSPECTION	Inspection	NC
Boiler - General	0	11/02/08 20:00	11/13/08 13:33	20	20	2OIL	30.66	257.55	0.00	BOILER MISCELLANEOUS	Economy	NC
Coal Mill 2	0	11/15/08 10:47	11/15/08 14:35	20	20	2OIL	0.45	3.80	0.00	PULVERIZER MILLS	Failure	D1
Coal Mill 2	0	11/15/08 11:25	11/15/08 14:29	20	20	2OIL	0.37	3.07	0.00	PULVERIZER MILLS	Failure	D1
Coal Mill 3	0	11/23/08 23:00	11/26/08 15:00				0.00	64.00	0.00	PULVERIZER FIRES	Inspection	NC
Turbine - General	0	12/01/08 00:00	12/01/08 04:17				0.00	4.28	0.00	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Turbine - General	400	12/09/08 00:00	12/09/08 06:00				0.00	6.00	14.29	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Boiler - General	15	12/09/08 08:47	12/14/08 18:00				0.00	129.22	11.54	BOILER SCREEN-WING WALL OR SLAG SCREEN SLAGGING/FOULING(WATER TUBES ONLY)	Slagging	NC
Boiler - General	70	12/09/08 13:56	12/09/08 22:00				0.00	8.07	3.36	BOILER SCREEN-WING WALL OR SLAG SCREEN SLAGGING/FOULING(WATER TUBES ONLY)	Slagging	D1
Boiler - General	15	12/09/08 22:00	12/16/08 08:51				0.00	154.85	13.83	BOILER SCREEN-WING WALL OR SLAG SCREEN SLAGGING/FOULING(WATER TUBES ONLY)	Slagging	D1
Boiler - General	60	12/15/08 11:29	12/24/08 02:00	60			73.76	206.52	73.76	BOILER MISCELLANEOUS	Economy	NC
Coal Mill 5	0	12/17/08 06:00	12/18/08 04:30	30	30	2OIL	4.02	22.50	0.00	PULVERIZER LUBE OIL SYSTEM	Leaks	D1
Turbine - General	0	12/17/08 08:00	12/17/08 10:58				0.00	2.97	0.00	TURBINE CONTROL VALVE TESTING	Testing	NC
Boiler Feed Pump General	365	12/22/08 05:04	12/22/08 13:30				0.00	8.43	18.32	FEEDWATER PUMP	Shorted electrical component	D1
Boiler - General	725	12/22/08 20:36	12/23/08 06:15				0.00	9.65	41.64	COMBUSTION/STEAM CONDITION CONTROLS	Controls	U1

EVENT HISTORY DETAIL REPORT

For Period: 08/01/2008 00:00 --- 06/02/2010 12:00

Plant MONPP
Unit 2

MPAC Id	MW Loss	Start Date	End Date	Fuel Loss	Fuel Gain	Gain Type	Fuel loss mwwks	Hours	Weeks	Nerc Description	Failure	Event Type
Boiler - General	25	12/23/08 06:15	12/31/08 00:00				0.00	185.75	27.64	HP HEATER TUBE LEAKS	Leaks	NC
Turbine - General	320	12/26/08 01:00	12/26/08 12:50				0.00	11.83	22.54	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Boiler - General	100	12/28/08 00:26	12/30/08 00:11				0.00	47.75	28.42	FORCED DRAFT FAN DRIVES(OTHER THAN MOTOR)	Restricted	D1
Boiler - General	430	12/30/08 00:13	12/30/08 23:59				0.00	23.77	60.83	FORCED DRAFT FAN DRIVES(OTHER THAN MOTOR)	Restricted	D1
Boiler - General	795	12/31/08 00:00	01/07/09 06:38				0.00	174.63	826.39	FORCED DRAFT FAN DRIVES(OTHER THAN MOTOR)	Restricted	U1
Boiler Feed Pump General	385	01/09/09 20:05	01/10/09 04:07				0.00	8.03	18.41	OTHER FEEDWATER PUMP PROBLEMS	Leaks	D1
Turbine - General	10	01/10/09 22:04	01/20/09 23:50				0.00	241.77	14.39	HP TURBINE BUCKETS OR BLADES	Balance, not within limits	D1
Boiler - General	135	01/14/09 05:18	01/15/09 22:35	185	50	2OIL	45.46	41.28	33.17	COAL CONVEYORS AND FEEDERS	Broken	D1
Turbine - General	785	01/18/09 00:44	01/19/09 00:57				0.00	24.22	113.16	480-VOLT CIRCUIT BREAKERS	Burned/fire damage - initiated by compon	U1
Turbine - General	10	01/20/09 23:51	08/28/09 01:08				0.00	5257.28	312.93	HP TURBINE BUCKETS OR BLADES	Balance, not within limits	NC
Coal Mill 3	0	01/21/09 20:00	02/19/09 16:51	20	20	2OIL	82.48	692.85	0.00	PULVERIZER INSPECTION	Inspection	NC
Boiler - General	0	01/29/09 08:00	01/29/09 16:30				0.00	8.50	0.00	BOILER PERFORMANCE TESTING	Testing	NC
Boiler - General	270	02/02/09 18:00	02/04/09 13:00				0.00	43.00	69.11	LACK OF FUEL	Economy	NC
Boiler - General	0	02/03/09 10:44	02/04/09 15:30				0.00	28.77	0.00	BOILER MISCELLANEOUS	Failure	D1
Turbine - General	0	02/08/09 00:00	02/08/09 03:00				0.00	3.00	0.00	TURBINE PERFORMANCE TESTING	Testing	NC
Boiler - General	315	02/12/09 08:01	02/12/09 11:04				0.00	3.05	5.72	OTHER FLUE GAS PROBLEMS	Stack emissions	D1
Turbine - General	0	02/15/09 00:00	02/15/09 02:00				0.00	2.00	0.00	TURBINE CONTROL VALVE TESTING	Testing	NC
Turbine - General	0	02/22/09 00:00	02/22/09 00:37				0.00	0.62	0.00	TURBINE CONTROL VALVE TESTING	Testing	NC
Turbine - General	260	02/22/09 01:00	02/22/09 04:41				0.00	3.68	5.70	OTHER LOW PRESSURE TURBINE PROBLEMS	Back pressure	D1
Boiler - General	0	03/04/09 07:55	03/05/09 03:03				0.00	19.13	0.00	BOILER MISCELLANEOUS	Stack emissions	D1
Boiler - General	785	03/05/09 03:03	03/07/09 04:00				0.00	48.95	228.72	ELECTROSTATIC PRECIPITATOR PROBLEMS	Grounded electrical component	U1
Boiler - General	785	03/07/09 04:00	03/16/09 17:25				0.00	229.42	1071.98	BOILER INSPECTIONS	Inspection	U1
Boiler - General	190	03/16/09 17:28	03/18/09 17:35				0.00	48.12	54.42	OTHER FEEDWATER SYSTEM PROBLEMS	Lubrication - lack of	D2
Turbine - General	0	03/31/09 01:00	03/31/09 05:37				0.00	4.62	0.00	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Coal Mill 4	0	04/06/09 04:03	04/08/09 16:13				0.00	60.17	0.00	LIGHT OFF (IGNITER) SYSTEMS(INCL FUEL SUPPLY)	Failed to start	D1
Coal Mill 1	20	04/13/09 20:00	04/14/09 08:34	20			1.50	12.57	1.50	PULVERIZER INSPECTION	Inspection	D1

Plant MONPP

Unit 2

MPAC Id	MW Loss	Start Date	End Date	Fuel Loss	Fuel Gain	Gain Type	Fuel loss mwwks	Hours	Weeks	Nerc Description	Failure	Event Type
Coal Mill 7	20	04/14/09 08:47	04/17/09 16:44				0.00	79.95	9.52	FOREIGN OBJECT IN MILL	Noisy	D1
Coal Mill 1	0	04/20/09 23:00	04/29/09 22:50				0.00	215.83	0.00	PULVERIZER INSPECTION	Inspection	NC
Turbine - General	0	04/21/09 01:00	04/21/09 02:00				0.00	1.00	0.00	TURBINE TRIP DEVICES (INCLUDING INSTRUMENTS)	Testing	NC
Turbine - General	0	04/26/09 01:00	04/26/09 01:37				0.00	0.62	0.00	TURBINE CONTROL VALVE TESTING	Testing	NC
Coal Mill 3	90	04/28/09 18:57	04/29/09 22:50	90			14.94	27.88	14.94	PULVERIZER MOTORS AND DRIVES	Failure	D1
Coal Mill 3	30	04/29/09 22:50	05/06/09 06:00				0.00	151.17	26.99	PULVERIZER MOTORS AND DRIVES	Failure	NC
Boiler - General	0	05/01/09 19:00	05/01/09 21:30				0.00	2.50	0.00	CEMS CERTIFICATION AND RECERTIFICATION	Testing	NC
Boiler - General	170	05/01/09 22:30	05/02/09 01:00				0.00	2.50	2.53	CEMS CERTIFICATION AND RECERTIFICATION	Testing	NC
Boiler - General	330	05/02/09 02:00	05/02/09 05:00				0.00	3.00	5.89	CEMS CERTIFICATION AND RECERTIFICATION	Testing	NC
Boiler - General	0	05/02/09 19:00	05/02/09 21:30				0.00	2.50	0.00	CEMS CERTIFICATION AND RECERTIFICATION	Testing	NC
Boiler - General	170	05/02/09 22:30	05/03/09 01:00				0.00	2.50	2.53	CEMS CERTIFICATION AND RECERTIFICATION	Testing	NC
Coal Mill 6	85	05/05/09 14:39	05/06/09 03:00	135	50	2OIL	9.92	12.35	6.25	PULVERIZER FEEDERS	Broken	D1
Coal Mill 3	30	05/06/09 06:00	05/07/09 03:35				0.00	21.58	3.85	PULVERIZER MOTORS AND DRIVES	Broken	NC
Boiler - General	150	05/06/09 23:00	05/07/09 02:49				0.00	3.82	3.41	CONDENSATE POLISHING AND FILTERING SYSTEMS	Restricted	NC
Coal Mill 4	45	05/08/09 17:05	05/09/09 15:33	45			6.02	22.47	6.02	PULVERIZER FEEDERS	Failure	D1
Coal Mill 6	110	05/09/09 04:20	05/09/09 16:49	110			8.17	12.48	8.17	PULVERIZER FEEDERS	Electrical	D1
Coal Mill 4	100	05/09/09 16:42	05/14/09 15:05	100			70.47	118.38	70.47	PULVERIZER MILLS	Leaks	D1
Coal Mill 4	45	05/10/09 06:59	05/14/09 01:42	45			24.30	90.72	24.30	PULVERIZER FUEL AND AIR PIPING(PULVERIZER TO WINDBOX)	Leaks	D1
Boiler - General	52	05/10/09 07:12	05/14/09 15:07				0.00	103.92	32.16	GENERATING TUBES SLAGGING/FOULING	Slagging	D1
Turbine - General	375	05/11/09 01:00	05/11/09 07:00				0.00	6.00	13.39	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
N. Heater Feed Pump	50	05/11/09 10:30	05/13/09 01:23				0.00	38.88	11.57	CONDENSATE BOOSTER PUMPS	Leaks	D1
N. Heater Feed Pump	75	05/13/09 01:25	05/14/09 01:24				0.00	23.98	10.71	CONDENSATE BOOSTER PUMPS	Failure	D1
Turbine - General	3	05/13/09 01:29	05/19/09 21:17				0.00	163.80	2.93	HIGH CIRCULATING WATER TEMPERATURE	Temperature limits	NC
N. Heater Feed Pump	75	05/14/09 01:30	05/14/09 12:00				0.00	10.50	4.69	CONDENSATE BOOSTER PUMPS	Failure	D1
Turbine -	172	05/19/09 02:00	05/19/09 03:00				0.00	1.00	1.02	OTHER VOLTAGE CONDUCTORS	Temperature limits	NC

EVENT HISTORY DETAIL REPORT

For Period: 08/01/2008 00:00 --- 06/02/2010 12:00

Plant MONPP
Unit 2

MPAC Id	MW Loss	Start Date	End Date	Fuel Loss	Fuel Gain	Gain Type	Fuel loss mwwks	Hours	Weeks	Nerc Description	Failure	Event Type
General										AND BUSES		
Boiler - General	775	05/19/09 21:17	05/24/09 21:17				0.00	120.00	553.57	SECOND REHEATER LEAKS	Leaks	U1
Boiler - General	775	05/24/09 21:18	05/31/09 11:35				0.00	158.28	730.18	AIR HEATER FOULING (REGENERATIVE)	Maintenance - general	U1
Boiler - General	35	06/01/09 14:17	06/03/09 07:28				0.00	41.18	8.58	BOILER MISCELLANEOUS	Failure	D1
Coal Mill 6	0	06/01/09 20:00	06/18/09 06:22	35	35	2OIL	82.16	394.37	0.00	PULVERIZER INSPECTION	Inspection	NC
Turbine - General	0	06/02/09 01:00	06/02/09 07:00				0.00	6.00	0.00	CONDENSER TUBE FOULING TUBE SIDE	Cleaning	NC
Boiler - General	155	06/09/09 08:55	06/11/09 02:50				0.00	41.92	38.67	CONDENSATE POLISHING AND FILTERING SYSTEMS	Clogged	D1
Turbine - General	70	06/11/09 04:16	06/25/09 10:45				0.00	342.48	142.70	CONDENSATE POLISHING AND FILTERING SYSTEMS	Restricted	D1
Boiler - General	45	06/13/09 08:30	06/15/09 14:44				0.00	54.23	14.53	ELECTROSTATIC PRECIPITATOR PROBLEMS	Stack emissions	D1
Boiler - General	15	06/17/09 07:02	06/19/09 22:03				0.00	63.02	5.63	CONDENSATE POLISHING AND FILTERING SYSTEMS	Plugged	D1
Turbine - General	10	06/17/09 17:25	06/22/09 15:28				0.00	118.05	7.03	OTHER CIRCULATING WATER SYSTEM PROBLEMS	Temperature limits	D1
Turbine - General	300	06/21/09 23:30	06/22/09 03:30				0.00	4.00	7.14	CONDENSER TUBE SHEET FOULING	Cleaning	NC
Boiler - General	40	06/25/09 16:47	06/29/09 16:52				0.00	96.08	22.88	INDUCED DRAFT FANS	Balance, not within limits	D1
Turbine - General	375	06/25/09 23:00	06/26/09 04:03				0.00	5.05	11.27	OTHER MISC STEAM TURBINE PROBLEMS	Cleaning	NC
Coal Mill 4	55	06/26/09 23:01	06/29/09 16:45	55			21.52	65.73	21.52	PULVERIZER FEEDER MOTOR	Broken	D1
Turbine - General	0	07/08/09 07:00	07/08/09 23:00				0.00	16.00	0.00	TURBINE PERFORMANCE TESTING	Testing	NC
Turbine - General	0	07/12/09 23:00	07/13/09 04:51				0.00	5.85	0.00	TURBINE CROSSOVER OR UNDERPIPING	Cleaning	NC
Boiler - General	100	07/22/09 08:30	07/22/09 11:30				0.00	3.00	1.79	ELECTROSTATIC PRECIPITATOR PROBLEMS	Failure	D1
Turbine - General	400	07/26/09 01:00	07/26/09 06:00				0.00	5.00	11.90	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Coal Mill 6	0	07/29/09 01:37	07/29/09 03:55	30	30	2OIL	0.41	2.30	0.00	PULVERIZER MILLS	Plugged	D1
Turbine - General	375	08/03/09 01:00	08/03/09 06:00				0.00	5.00	11.16	TURBINE MISC TURBINE PIPING	Restricted	NC
Boiler - General	10	08/04/09 15:09	08/05/09 06:53				0.00	15.73	0.94	INDUCED DRAFT FANS	Overload	D1
Boiler - General	30	08/05/09 06:57	08/12/09 09:12				0.00	170.25	30.40	INDUCED DRAFT FANS	Restricted	D1
Turbine - General	0	08/08/09 01:00	08/08/09 07:00				0.00	6.00	0.00	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Boiler - General	50	08/09/09 01:00	08/12/09 04:54				0.00	75.90	22.59	INDUCED DRAFT FANS	Restricted	D1
Boiler - General	25	08/09/09 16:56	08/12/09 04:52				0.00	59.93	8.92	INDUCED DRAFT FANS	Restricted	D1
Coal Mill 5	0	08/10/09 02:00	08/28/09 01:08	0			0.00	431.13	0.00	PULVERIZER MILLS	Inspection	NC

EVENT HISTORY DETAIL REPORT

For Period: 08/01/2008 00:00 --- 06/02/2010 12:00

Plant MONPP
Unit 2

MPAC Id	MW Loss	Start Date	End Date	Fuel Loss	Fuel Gain	Gain Type	Fuel loss mwwks	Hours	Weeks	Nerc Description	Failure	Event Type
Boiler - General	65	08/12/09 01:00	08/28/09 01:08				0.00	384.13	148.62	INDUCED DRAFT FANS	Overload	D1
Turbine - General	370	08/15/09 01:00	08/15/09 05:00				0.00	4.00	8.81	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Boiler - General	0	08/18/09 08:00	08/18/09 18:00				0.00	10.00	0.00	OPACITY STACK EMISSIONS (FOSSIL)	Testing	NC
Boiler - General	110	08/18/09 14:30	08/19/09 07:41				0.00	17.18	11.25	BURNER MANAGEMENT SYSTEM	Low BTU fuel	D1
Boiler - General	25	08/19/09 22:00	08/20/09 15:00				0.00	17.00	2.53	PULVERIZER MILLS	Restricted	D1
Turbine - General	305	08/20/09 01:00	08/20/09 03:56				0.00	2.93	5.33	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Boiler - General	685	08/20/09 03:56	08/20/09 11:06				0.00	7.17	29.22	FEEDWATER PUMP	Controls	U1
Coal Mill 7	105	08/20/09 15:00	08/21/09 18:00	155	50	2OIL	24.91	27.00	16.88	PULVERIZER FEEDERS	Failure	D1
Boiler - General	245	08/22/09 06:00	08/28/09 01:08				0.00	139.13	202.90	FORCED DRAFT FANS	Broken	D1
N. FD Fan	785	08/28/09 01:08	09/01/09 17:20				0.00	112.20	524.27	AIR SUPPLY DAMPERS	Seized (not moving)	U3
Turbine - General	10	09/02/09 07:04	09/06/09 19:25				0.00	108.35	6.45	HP TURBINE BUCKETS OR BLADES	Balance, not within limits	NC
Coal Mill 5	0	09/02/09 09:08	09/05/09 19:00	50	50	2OIL	24.37	81.87	0.00	PULVERIZER MILLS	Plugged	D1
Boiler - General	30	09/03/09 04:03	09/03/09 20:29				0.00	16.43	2.93	COAL CONVEYOR SCALES-STORAGE COAL PILE	Failure	D2
Coal Mill 7	0	09/06/09 06:45	09/06/09 09:54	20	20	2OIL	0.38	3.15	0.00	PULVERIZER MILLS	Instrumentation	D1
Coal Mill 2	0	09/06/09 15:55	09/06/09 19:25	20	20	2OIL	0.42	3.50	0.00	PULVERIZER FEEDERS	Controls	D1
Boiler - General	785	09/06/09 19:25	09/10/09 09:12				0.00	85.78	400.83	ECONOMIZER LEAKS	Leaks	U1
Boiler - General	785	09/10/09 12:08	09/10/09 22:43				0.00	10.58	49.45	OTHER BOILER CONTROL PROBLEMS	Failure	U1
S. Boiler Feed Pump	405	09/11/09 03:21	09/11/09 22:15				0.00	18.90	45.56	FEEDWATER PUMP	Plugged	D1
Turbine - General	400	09/13/09 23:00	09/14/09 02:35				0.00	3.58	8.53	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Turbine - General	390	09/23/09 01:00	09/23/09 04:08				0.00	3.13	7.27	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Boiler - General	50	09/23/09 08:00	09/25/09 09:41				0.00	49.68	14.79	INDUCED DRAFT FANS	Overload	D1
Turbine - General	405	10/04/09 01:00	10/04/09 05:30				0.00	4.50	10.85	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Boiler - General	785	10/04/09 18:18	10/07/09 19:56				0.00	73.63	344.06	CONVECTION PASS WALL WATER TUBES ONLY LEAKS	Leaks	U1
Coal Mill 4	20	10/08/09 08:16	10/08/09 11:00	20			0.33	2.73	0.33	PULVERIZER MILLS	Failure	D1
Turbine - General	345	10/14/09 00:01	10/14/09 06:30				0.00	6.48	13.31	CONDENSER TUBE AND WATER BOX CLEANING	Cleaning	NC
Coal Mill 6	40	10/24/09 06:00	10/24/09 18:00	40			2.86	12.00	2.86	PULVERIZER FEEDER MOTOR	Failure	D1
Boiler - General	95	10/26/09 03:41	10/26/09 17:34				0.00	13.88	7.85	OTHER AUXILIARY STEAM PROBLEMS	Overload	PD
Coal Mill 7	30	11/01/09 07:56	11/09/09 22:44	30			36.93	206.80	36.93	PULVERIZER FEEDER MOTOR	Broken	D1

EVENT HISTORY DETAIL REPORT

For Period: 08/01/2008 00:00 --- 06/02/2010 12:00

Plant MONPP
Unit 2

MPAC Id	MW Loss	Start Date	End Date	Fuel Loss	Fuel Gain	Gain Type	Fuel loss mwwks	Hours	Weeks	Nerc Description	Failure	Event Type
Boiler - General	20	11/01/09 16:38	11/02/09 07:50				0.00	15.20	1.81	REHEAT STEAM PIPING UP TO TURBINE STOP VALVES	Overload	NC
Turbine - General	0	11/03/09 01:00	11/03/09 03:00				0.00	2.00	0.00	CIRCULATING WATER PUMPS	Testing	NC
Coal Mill 4	150	11/06/09 00:00	11/06/09 04:57				0.00	4.95	4.42	PULVERIZER COAL LEAK(PULVERIZERS ONLY)	Leaks	D1
Coal Mill 3	0	11/15/09 20:00	12/18/09 15:42	20	20	2OIL	93.77	787.70	0.00	PULVERIZER INSPECTION	Inspection	NC
Coal Mill 1	90	11/30/09 07:00	11/30/09 17:30	120	30	2OIL	7.50	10.50	5.63	PULVERIZER FEEDERS	Broken	D1
Boiler - General	795	12/06/09 16:00	12/11/09 10:34				0.00	114.57	542.15	FURNACE WALL LEAKS	Leaks	U1
Boiler - General	0	12/11/09 08:43	01/28/10 16:06				0.00	1159.38	0.00	HP HEATER TUBE LEAKS	Leaks	NC
Coal Mill 6	175	12/11/09 21:21	12/12/09 16:00	175			19.43	18.65	19.43	PULVERIZER MILLS	Clogged	D1
Turbine - General	125	12/18/09 20:00	12/19/09 08:56				0.00	12.93	9.62	CONDENSATE POLISHING AND FILTERING SYSTEMS	Failure	D1
Boiler - General	35	12/21/09 12:00	12/21/09 16:54				0.00	4.90	1.02	CONDENSATE POLISHING AND FILTERING SYSTEMS	Contaminated - liquid fluids	D1
Coal Mill 6	40	12/26/09 15:55	12/28/09 04:00	40			8.59	36.08	8.59	PULVERIZER MILLS	Failure	D1
MTG - Generator	405	12/27/09 23:59	12/28/09 04:27				0.00	4.47	10.77	GENERATOR OTHER COOLING SYSTEM PROBLEMS	Temperature limits	D1
S. ID Fan	45	01/05/10 05:16	01/09/10 13:17				0.00	104.02	27.86	INDUCED DRAFT FAN MOTORS - VARIABLE SPEED	Electrical	D1
Coal Mill 7	30	01/09/10 13:19	01/09/10 17:05	80	50	2OIL	1.79	3.77	0.67	PULVERIZER FEEDERS	Broken	D1
Boiler - General	795	01/25/10 06:00	01/29/10 23:54				0.00	113.90	538.99	ECONOMIZER LEAKS	Leaks	U1
Boiler - General	795	01/30/10 02:19	01/30/10 08:05				0.00	5.77	27.29	Secondary Air Fans/Blowers	Indication, false	U1
Coal Mill 5	0	02/01/10 03:26	02/01/10 13:59	30	30	2OIL	1.88	10.55	0.00	Igniters	Controls	D1
Boiler - General	90	02/05/10 00:00	02/05/10 04:00				0.00	4.00	2.14	BOILER WATER CONDITION(NOT FDWTR WATER QUALITY)	Plugged	D1
Coal Mill 6	5	02/05/10 16:53	02/08/10 15:30	55	50	2OIL	23.12	70.62	2.10	OTHER BURNER PROBLEMS	Leaks	D1
Turbine - General	0	02/07/10 01:00	02/07/10 01:55				0.00	0.92	0.00	TURBINE MAIN STOP VALVE TESTING	Testing	NC
Boiler - General	15	02/09/10 00:18	03/13/10 02:00				0.00	769.70	68.72	HP HEATER TUBE LEAKS	Leaks	NC
Coal Mill 2	0	02/09/10 00:22	02/15/10 18:00	40	40	2OIL	38.48	161.63	0.00	PULVERIZER FEEDER MOTOR	Overload	D1
Turbine - General	405	02/13/10 23:00	02/14/10 09:45				0.00	10.75	25.92	CONDENSER TUBE LEAKS	Leaks	NC
S. ID Fan	60	02/15/10 07:31	02/16/10 08:27				0.00	24.93	8.90	INDUCED DRAFT FAN MOTORS AND DRIVES	Restricted	D1
Coal Mill 2	0	02/17/10 08:00	02/25/10 15:43	30	30	2OIL	35.66	199.72	0.00	PULVERIZER FEEDERS	Broken	D1
Boiler - General	0	02/18/10 08:00	02/18/10 16:40				0.00	8.67	0.00	OPACITY STACK EMISSIONS (FOSSIL)	Testing	NC
S. Boiler Feed Pump Turbine	390	02/19/10 00:00	02/19/10 06:00				0.00	6.00	13.93	FEEDWATER PUMP	Leaks	NC
Boiler - General	0	02/19/10 18:00	02/19/10 23:15				0.00	5.25	0.00	PARTICULATE STACK EMISSIONS	Testing	NC

EVENT HISTORY DETAIL REPORT

For Period: 08/01/2008 00:00 --- 06/02/2010 12:00

Plant MONPP
Unit 2

MPAC Id	MW Loss	Start Date	End Date	Fuel Loss	Fuel Gain	Gain Type	Fuel loss mwwks	Hours	Weeks	Nerc Description	Failure	Event Type
Coal Mill 5	175	02/22/10 04:30	02/24/10 06:00	175			51.56	49.50	51.56	PULVERIZER MILLS	Leaks	D1
Coal Mill 7	175	02/24/10 06:00	02/24/10 16:00	195	20	2OIL	11.61	10.00	10.42	PULVERIZER FEEDERS	Failure	D1
N. FD Fan	165	02/24/10 21:57	02/25/10 15:42				0.00	17.75	17.43	FORCED DRAFT FANS	Sticking	D1
N. FD Fan	95	02/25/10 15:59	03/08/10 15:00				0.00	263.02	148.73	FORCED DRAFT FANS	Sticking	D1
Coal Mill 2	0	02/25/10 16:05	03/13/10 02:00	20	20	2OIL	44.04	369.92	0.00	PULVERIZER FEEDERS	Broken	NC
N. FD Fan	130	03/08/10 15:00	03/13/10 02:00				0.00	107.00	82.80	FORCED DRAFT FANS	Sticking	D1
Boiler - General	795	03/13/10 02:00						1954.00	9246.61	MAJOR BOILER OVERHAUL (720 HOURS OR LONGER)	Periodic inspection	PO
Sum							914.53	26108.28	19798.00			
Plant Sum							914.53	26108.28	19798.00			
Total							914.53	26108.28	19798.00			

Exhibit 2-G

DTE Energy Company
One Energy Plaza, Detroit, MI 48226-1279

DTE Energy

MICHAEL J. SOLO, JR.
Attorney
(313) 235-9512

June 3, 2010

Mark Palermo
Associate Regional Counsel
U.S. Environmental Protection Agency—Region 5
77 West Jackson Boulevard
Chicago, Illinois 60604

Re: Request to Provide Additional Information Pursuant to the Clean Air Act dated June 2, 2010

Dear Mr. Palermo:

Enclosed with this letter please find The Detroit Edison Company's ("Detroit Edison") response to the United States Environmental Protection Agency's ("EPA") June 2, 2010 request to provide additional information to Detroit Edison's response to the EPA's Clean Air Act Information Request, dated May 28, 2010.

The request for additional information provided Detroit Edison less than one business day to respond by demanding that the response be provided by 10:00 a.m. June 3, 2010. This request is on the heal of the initial request sent late on Friday afternoon prior to the Memorial Day Holiday weekend that afforded Detroit Edison approximately one business day to provide its response. Due to this unreasonably short period of time for Detroit Edison to provide the requested information, Detroit Edison's reserves the right to amend or supplement this response. Detroit Edison is perplexed by this action regarding an outage to maintain a unit, and which will not increase emissions. As explained previously, the model projected increase in emissions in 2013 which seems to be driving this action is a result of a projected (hoped for) increase in demand and an outage on a sister unit at the plant to tie in a flue gas desulfurization unit being installed to significantly reduce emissions. In addition, as we have explained, assumptions today would likely not project any emission increase, even 3 years from now.

Detroit Edison objects to the extent the request is: (1) not related to whether Detroit Edison has been in compliance with applicable provisions of the federal Clean Air Act; (2) seeks information that is confidential and/or privileged; and/or (3) beyond the scope of EPA's legal authority. Further, by providing this response, Detroit Edison does not admit or acknowledge any noncompliance whatsoever with regard to the Clean Air Act, the Michigan State Implementation Plan or any other matter.

In the June 2, 2010 request for additional information, EPA requested Detroit Edison to provide all availability and outage rates used as inputs for Monroe Unit 2 in the PROMOD analysis that was used in support of the Power Supply Cost Recovery 2010 Annual Report referenced in Detroit Edison's June 1 and March 12 letters. Please see the attached document for the requested information.

In addition, EPA requested clarification regarding contradictory information from the May 2005 to April 2007 baseline period. The chart provided with Detroit Edison's March 12, 2010 notice to MDNRE included a typographical error. The error placed the units equivalent availability factor (EAF) in the field representing capacity factor. The capacity factor for Unit 2 between May, 2005 and April, 2007, was 72.2%, not the 85.5% included on the chart. The equivalent availability factor (EAF) for that period was 85.5%. The net generation and heat input figures contained in the table reflect the correct capacity factor of 72.2% for the baseline period.

I trust that you will find this response to the additional requested information satisfactory. If you have any questions regarding this submission, please contact the undersigned.

Very truly yours,

Michael J. Solo, Jr.

MJS/dmc
Enclosure
cc: William Presson , MDNRE
Ethan Chatfield, EPA Region 5
Skiles Boyd, Detroit Edison
William Brunell, Detroit Edison Counsel

PSCR 2010
MAINTENANCE SCHEDULE - PROMOD INPUT

Plant Name	Unit Number	Start Date	End Date
MnreMI	2	3/6/2010	5/26/2010
MnreMI	2	6/11/2010	6/15/2010
MnreMI	2	10/25/2012	11/21/2012
MnreMI	2	9/17/2013	9/24/2013
MnreMI	2	3/1/2014	5/7/2014
MnreMI	2	9/17/2014	9/24/2014

FILE: Monroe 2 - PROMOD input & output.xlsx
TAB: Maintenance Schedule - Input

PSCR 2010
PROMOD OUTPUT - MONROE 2 (only)

	2010	2011	2012	2013	2014
UNIT DATA					
NO2 Oil - Heat Consumed - (thousands of mmBTU	81	110	102	110	91
Coal Heat Consumed - (kMBTu)	40,600	54,724	50,984	54,864	45,305
Coal Consumed - Tons					
MSE	699	969	910	1,049	901
LSW	1,306	1,722	1,594	1,616	1,284
Total	2,005	2,691	2,504	2,664	2,185
Generation - GWh	4,217	5,700	5,322	5,748	4,739
Heat Rate - BTU/KWh	9,646	9,619	9,600	9,564	9,579
Average Loading - MW	698	709	718	735	750
Operating Hours - Hours	6,040	8,039	7,414	7,825	6,320
Equivalent Availability - %	69%	92%	84%	89%	72%
Loading Factor - %	88%	89%	90%	92%	96%
Periodic - %	24%	0%	8%	2%	21%
Random Outage Factor (ROF) - %	7%	8%	8%	8%	7%
Random Outage Factor (ROR) - %	9.5%	8.3%	8.7%	8.7%	8.9%
Capacity Factor - %	60.6%	81.9%	76.2%	82.5%	69.0%
Operating Capacity - MW's	703	712	720	736	754
EMISSION DATA - (stack weighted in 2010-2012, until Scrubber Installation)					
PM Tons	451	610	570	615	507
HG Tons	148,737	200,481	173,065	200,994	164,485
HG Rate lb/mbtu	7.312	7.312	6.775	7.312	7.247
SO2 Tons	23,811	32,512	30,403	33,816	6,956
SO2 Rate lb/mbtu	1.171	1.186	1.190	1.230	0.306
SO2 Dispatch Cost - ($/MWh)	$0.236	$0.244	$0.249	$0.260	$0.069
NOx Tons	5,226	8,345	7,395	14,494	11,857
NOx Rate - lb/mbtu	0.257	0.304	0.290	0.527	0.522
NOx Dispatch Cost - ($/MBTU)	$0.17	$0.11	$0.08	$0.08	$0.08
SO2 Dispatch Cost - ($/MWh)	$1.68	$1.02	$0.73	$0.80	$0.80
DISPATCH COST(S)					
Total Dispatch Cost - $/MBTU	$2.45	$3.10	$3.22	$3.30	$3.40
Total Dispatch Cost - $/MWh	$23.67	$29.82	$30.91	$31.61	$32.57
Fuel Dispatch Cost - $/MBTU (by fuel type)					
LSW	$1.56	$2.39	$2.56	$2.63	$2.76
MSE	$2.84	$3.37	$3.47	$3.50	$3.56
MN2 (No.2 oil)	$15.48	$16.66	$17.14	$16.86	$17.33
Fuel Dispatch Cost - $/MWh	$20.68	$27.48	$28.78	$29.40	$30.55
Variable O&M $/MBTu	$0.11	$0.11	$0.12	$0.12	$0.12
FUEL BLEND					
Fuel Blend by BTU (Coal) - %					
LSW	57%	55%	55%	52%	50%
MSE	43%	45%	45%	48%	50%
Fuel Blend by Weight (Coal) - %					
LSW	65%	64%	64%	61%	59%
MSE	35%	36%	36%	39%	41%

Exhibit 2-H

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-15768
its rate schedules and rules governing the	)	
distribution and supply of electric energy	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

PAUL FESSLER

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF PAUL FESSLER

Line No.

1 **Q. What is your full name, title, and business address?**

2 A. My name is Paul Fessler. I am Vice President of Fossil Generation for The
3 Detroit Edison Company. My business address is One Energy Plaza,
4 Detroit, Michigan 48226.

5

6 **Q. What is your educational background?**

7 A. I received a Bachelor of Science Degree in 1974 and a Master of Science
8 Degree in Nuclear Engineering in 1976 from University of Michigan I
9 received an MBA degree in 1984 from the University of Michigan

10

11 **Q. What is your work experience?**

12 A. I was hired by The Detroit Company Edison Company ("Detroit Edison" or
13 "the Company") as an associate engineer in 1976. In that capacity, I was
14 responsible for troubleshooting, performance improvements and outage
15 management for Unit 3 at the Monroe Power Plant.

16

17 In 1977, I was transferred by the Company to the Fermi 2 Nuclear Power
18 Plant. During my 24 years at Fermi I was responsible for ever increasing
19 breadth of duties. My job assignments included Startup test engineer –
20 Nuclear Steam Supply, Lead Startup test engineer – Nuclear Steam Supply,
21 Assistant Maintenance Manager, Maintenance Manager, Assistant
22 Operations Engineer, Supervisor Planning and Scheduling, Director Plant
23 Safety, Manager Systems Engineering, Manager Nuclear Training,
24 Technical Director and Plant Director.

25

Line No.

1 In 2001, I transferred to Fossil Generation as the Director of Monroe Power
2 Plant. As plant director I had full responsibility for the site including operations,
3 maintenance, budgets and safety of the approximately 450 site employees.
4
5 In 2006, I was promoted to General Director - Fossil Generation. In this
6 role, I was responsible for all aspects of Fossil Generation's large 9 site
7 power plant fleet. I was also responsible for the 85 peaking units operated
8 and maintained by Fossil Generation and the portion of Ludington Pumped
9 Storage facility owned by Detroit Edison.
10
11 **Q. What is your current position and what are your current**
12 **responsibilities?**
13 A. In October 2008, I was appointed Vice President of Fossil Generation for
14 Detroit Edison. In this capacity I am responsible for all phases of operations,
15 maintenance, engineering, planning and investment in the major Fossil
16 Fueled Power Plants, the 85 peaking units and our interests in the Ludington
17 pumped storage facility that is jointly owned with Consumers Energy.
18
19 **Q. Have you written any papers or publications, or given any lectures?**
20 A. I authored several papers and developed and delivered presentations at the
21 Institute of Nuclear Power Operations. While in Fossil Generation, I made
22 presentations at numerous industry conferences and conducted many
23 internal training sessions and lectures.
24
25 **Q. Are you a member of any trade associations or participate on any**

Line No.

1 **Boards or Committees?**

2 A. I am a member of the Engineering Society of Detroit, the American Nuclear
3 Society, a certified nuclear reactor operator, nuclear trainer and a level 3
4 mechanical, electrical and I&C inspector. I was also given a special
5 assignment by the U.S. State Department in 1990/91 to inspect nuclear
6 reactors in Russia and East Germany for the International Atomic Energy
7 Agency. I am currently a member of the Electric Power Research Institute
8 (EPRI) guidance counsel, responsible for setting research program plans for
9 the electric utility industry.

10

11 **Q. Have you previously provided testimony before the Commission?**

12 A. Yes, I provided testimony in Case No. U-10965-R (1996 PSCR
13 Reconciliation) and the 1993 Femi 2 turbine failure proceeding.
14 Furthermore, I provided support for Company witnesses in other General
15 Electric Rate cases and Power Supply Cost Recovery cases.

16

17 **Q. Are you registered as a professional engineer in the State of**
18 **Michigan?**

19 A. Yes, I became a registered engineer in the State of Michigan in 1979.

THE DETROIT EDISON COMPANY
DIRECT TESTIMONY OF PAUL FESSLER

Line No.

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

2 A. The purpose of my testimony is to explain the Fossil Generation capital,
3 operation and maintenance (O&M), and fuel handling expenses for the three
4 year period from July 2007 through July 2010. I will provide details for the
5 periods where costs are historical (actual 12 months ended June 2008) and
6 support as reasonable, prudent, and necessary, the Fossil Generation
7 capital, O&M and fuel handling expenses for the periods (July 2008 through
8 June 2009 and the projected period July 2009 through June 2010). In doing
9 so, I will show that despite many challenges, Detroit Edison expects to
10 improve plant availability levels while experiencing only modest increases in
11 capital and O&M expenditures.

12

13 **Q. Which exhibits are you supporting?**

14 A. I am supporting information on Schedules in the following exhibits:

15 Exhibit A-6

16 Schedule F1 Planned Long Range Generation Changes

17 Exhibit A-9

18 Schedule B6.1 Capital Expenditures – Steam, Hydraulic,
19 Environmental, Other Power Generation and MERC

20 Exhibit A-10

21 Schedule C5.1 O&M Expense – Steam Power Generation

22 Schedule C5.3 O&M Expense – Hydraulic Power Generation

23 Schedule C5.4 O&M Expense – Other Power Generation

24

25

Line No.

1 **Q. Were these exhibits prepared by you or under your direction?**

2 A. Yes, they were.

3

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

5 A. My testimony consists of the following three (3) parts:

6 Part I Plant Availability

7 Part II Capital Expenditures

8 Part III Operating and Maintenance Expenses

9

10 **Part I**

11 **Plant Availability**

12 **Q. Will you provide an overview of Detroit Edison's Fossil Generation**

13 **assets?**

14 A. As of July 31, 2008, Detroit Edison's total owned net summer operating

15 capability was 11,113 MW and is comprised of:

16

	Summer Capacity
Nuclear Steam	1,122 MW
Fossil Steam	7,973 MW
Pumped Storage	917 MW
Peaking Plant	1,101MW
Total Owned Capability	11,113 MW
Total Fossil System	9,982 MW

Line No.

1 Detroit Edison's Fossil Steam plant contains base load coal-fired units and
2 intermediate oil and/or natural gas-fired units. They are comprised of:

Coal Steam Plants	Summer Capacity	No. Units
Belle River (less MPPA)	1,026 MW	2
Harbor Beach	103 MW	1
Marysville	84 MW	1
Monroe	3,115 MW	4
River Rouge	523 MW	2
St. Clair	1,368 MW	6
Trenton Channel	730 MW	3
Total Coal Capacity (steam)	6,949 MW	19

Oil/Gas Steam Plants	Summer Capacity	No. Units
Conners Creek	239 MW	2
Greenwood	785 MW	1
Total Oil/Natural Gas (steam)	1,024 MW	3

The Michigan Public Power Agency ("MPPA") is joint owner of Belle River Power Plant and their ownership entitlement is effectively 18.61% (234 MW) of the plant. The MPPA ownership of Belle River is not included in the 1,026 MW Belle River Plant capability shown above.

Detroit Edison's ownership share of the Ludington Pumped Storage facility, which is jointly owned with Consumers Energy, along with Detroit Edison's Peaking plant, is shown below.

Line No.

Pumped Storage and Peaking	Summer Capacity	No. Units
Ludington Pumped Storage	917 MW	6
Gas Turbine Peaking (7 locations)	819 MW	25
Diesel Peaking (13 locations)	146 MW	55
Jet Peaking (3 location)	136 MW	5
Total Peaking Capacity	2,018 MW	91

As evidenced by the data provided, Detroit Edison's generating system is comprised of a diverse range of peaking, intermediate and base load units, varying in size and fuel types. This diversity of plant type and fuel gives Detroit Edison important flexibility required to meet the energy needs of its electric customers in a cost effective and reliable manner.

Q. Are the above-mentioned generating units in active service?

A. All are in active service with the exception of the Marysville plant, which is in cold standby.

Q. What do you mean by cold standby?

A. As defined by the U.S. Department of Energy – Energy Information Administration, a unit that is in cold standby "usually requires 3 – 6 months to reactivate".

Q. Are there any planned additions or reductions to the unit capacities listed above during the 2008-2010 period?

Line No.

1 A. Yes. A decrease of 25 MW is occurring over the 2008-2010 time period.
2 This occurs in 2009-10 due to the increased internal load requirements
3 associated with startup of new Flue Gas Desulfurization equipment
4 (scrubbers) on Monroe Units 3 and 4 for a combined 25 MW.
5
6 **Q. What standard or test is used to verify the capacity numbers stated**
7 **above?**
8 A. Fossil Generation performs Net Demonstrated Capacity (NDC) tests per
9 ECAR Document 4 guidelines and are based on 8 hours of data where the
10 highest achieved capacity in 7 out of 8 contiguous hours are averaged to
11 determine the unit's Net Demonstrated Capacity.
12
13 **Q. What is the relative age of Detroit Edison's installed fossil capacity?**
14 A. In 2009 the average age of the Company's 19 coal fired generation units will
15 be 43 years. The average age of the two gas/oil fired generation units is 45
16 years. The average age of the six pumped storage units at Ludington is 32
17 years.
18
19 Most of the 85 peaking units were installed in the mid to late 1960's, making
20 their average age approximately 40 years. The only exceptions are the two
21 rebuilt combustion turbines that were installed at Delray and the six
22 combustion turbines that were installed at the Greenwood and Belle River
23 Plants in 1999.
24
25 **Q. What is the significance of the age of Detroit Edison's fossil**

Line No.

1 **generation fleet?**

2 A. As generating plants age, they require significant maintenance resources to
3 keep them operating in an optimal and reliable condition. Detroit Edison
4 has experienced, and continues to experience, operational reliability issues
5 on major system components that need to be addressed through on-going
6 O&M and capital investments. Systems that have required replacements or
7 significant work have included air heaters, precipitators, main unit integrated
8 boiler and turbine control systems, superheater tubes, reheater tubes and
9 generator step-up transformers. Over the next few years, these types of
10 efforts are expected to continue.

11

12 **Q. What is the primary fossil fuel utilized by Detroit Edison power plants?**

13 A. Over 60 percent of Detroit Edison's generation capacity is coal-fired and
14 over the past 3 years approximately 83 percent of the total Detroit Edison
15 generation has been from its coal units.

16

17 Currently, Detroit Edison utilizes a mix of coals from both eastern
18 Appalachian (bituminous) regions and western Powder River Basin (sub-
19 bituminous) regions. Despite the fact that the vast majority of Detroit
20 Edison's fossil units were designed for eastern coals, the Company is
21 continuing its long history of increasing the use of cleaner, less expensive
22 western coals. Additionally, the Company is planning a significant increase
23 in western coal use at Monroe starting in 2011. In 2010/2011 Monroe Unit 3
24 is scheduled to undergo equipment modifications to allow increased use of
25 western coals while still sustaining current unit net demonstrated capacity

Line No.

1 ratings (NDC). After successful demonstration of the higher western coal
2 usage on Monroe Unit 3 the other Monroe units will be scheduled for similar
3 enhancements in later years.
4
5 The low delivered cost of western coal to Monroe Power Plant more than
6 offset higher operating, maintenance and capital costs resulting in lower
7 overall customer costs and environmental benefits.
8
9 **Q. Has Detroit Edison built any new units or re-started any older units**
10 **since the last general rate case U-15244?**
11 A. No.
12
13 **Q. How are plant availabilities calculated?**
14 A. Detroit Edison plant availability is calculated using Equivalent Availability as the
15 reporting measure. Simply stated, equivalent availability is Total Possible
16 Megawatt Weeks minus Periodic Megawatt Weeks minus Forced Megawatt
17 Weeks (full and partial derates) divided by Total Possible Megawatt Weeks.
18 Total Possible Megawatt Weeks is calculated by multiplying the Net
19 Demonstrated Capability of the unit by the weeks in the time period (52 weeks
20 per year). Periodic Megawatt Weeks refers to the equivalent number of weeks
21 in the time period that the unit is not available due to scheduled maintenance
22 times the capacity that is out of service. Forced Megawatt Weeks is the
23 number of weeks that a unit is not available due to an outage or derate not
24 planned or scheduled, multiplied by the capacity out of service.
25

Line No.

1 **Q. What are the major drivers of unit unavailability?**

2 A. There are three major drivers of unit unavailability: (1) planned full unit (or
3 periodic) outages, (2) unplanned (or random) unit outages, and (3) derates
4 or partial unit outages (which can be planned or unplanned).

5

6 Planned full unit outages are those outages for which the Company has
7 developed long range plans to execute repairs or maintenance and are
8 designed to proactively address emerging reliability issues and maintain unit
9 performance.

10

11 Unplanned unit outages are those that occur due to either systemic
12 reliability issues common across the Detroit Edison Fossil Generation fleet
13 (and industry) or unusual events which are unique to a specific plant or unit.

14

15 **Q. Will you explain the Company's 2007-2008 plant availability?**

16 A. Total fossil plant availability was 85.2% for the historic period July 2007-
17 June 2008. In U-14838 the 2006 fossil plant availability was 83.4 percent
18 and has been increasing since then as a focused effort on reducing planned
19 and unplanned unavailability is providing results. A breakout of the
20 unavailability during the period of June 2007 through July 2008 is outlined
21 below:

22

23 There was a 6.0% loss of total fossil fleet availability due to planned full unit
24 maintenance outages. This was driven by planned periodic maintenance that
25 included boiler overhauls on St. Clair Unit 3, St. Clair Unit 4, Monroe Unit 2,

Line No.

1 Monroe Unit 4, River Rouge Unit 2, Trenton 16-19 boilers and a major turbine
2 overhaul and boiler work on Belle River Unit 2.
3
4 The remaining 8.81% of fossil fleet unavailability in the July 2007 through
5 July 2008 time frame was due to unplanned unit outages. Most of these
6 outages were boiler related with the most predominant issue being boiler
7 tube leaks in waterwall, superheater, reheater or economizer sections.
8 One-time events contributed less than 1% to the loss of unit availability.
9
10 **Q. On what basis did you make your Detroit Edison forecast of plant**
11 **availability for 2008 and beyond?**
12 A. The Detroit Edison forecasted plant availabilities are based on input from
13 Plant Staff and plant-headquartered Reliability Engineers, historical unit
14 performance, known maintenance and operational status of each unit,
15 and future planned outage schedules and work scope. The impact of
16 new environmental equipment construction and operation was also
17 considered.
18
19 **Q. What are the projections for availability for 2008 through 2010?**
20 A. The availability of the Fossil Generation base load coal units is forecasted to
21 increase between 2008 and 2010. Base load coal unit availability is
22 forecasted to improve from 81.8 % in 2007 to 83.5% in 2010. This is driven
23 by a random outage factor improvement on coal units from 12.0% in 2007 to
24 9.1% in 2010. Base load coal plants include all coal fired units/plants
25 except Harbor Beach Power Plant.

Line No.

In summary, there is equivalent availability improvement in both the coal and peaking units over the 2007-2010 time period, with slight year to year variations driven by the cyclic nature of periodic outage scheduling.

Q. What is Detroit Edison doing to improve the overall availability of Fossil Generation units?

A. The Company's efforts to improve overall Fossil Generation availability can be categorized as follows:

Unplanned Outage Frequency Reduction – A formal Boiler Tube Failure Reduction team addresses all unplanned outages within the fossil fleet (and the industry in general). The focus of this team is to identify, prioritize, and recommend the most critical areas for boiler tube investment through equipment history, equipment inspection and data collection, and original equipment manufacturer (OEM) interface. The results of this team's efforts drive project planning at the O&M and Capital investment levels.

Planned Outage improvement – Fossil Generation has implemented a periodic outage execution improvement effort designed to decrease the duration and overall cost of planned outages without impacting the scope of work performed. That has generally been successful in lowering unit periodic outage factors which improves overall unit availability.

Q. Can you summarize Detroit Edison's efforts with respect to Fossil Generation Availability?

Line No.

1 A. Detroit Edison has invested significant capital and maintenance dollars over
2 the last several years to maintain and improve generation unit availability,
3 reduce overall plant costs, and to comply with new environmental
4 regulations. New environmental regulations combined with aging
5 equipment have and will continue to result in plant performance/availability
6 challenges.
7
8 **Part II**
9 **Capital Expenditures**
10 **Q. Can you explain the Fossil Generation capital planning process?**
11 A. The Fossil Generation Plant Improvement Projects (PIP) capital budget is
12 approved annually for expenditures during the next calendar year. The annual
13 budget is derived from projects defined by plant-level equipment reliability
14 plans, original equipment manufacturer (OEM) recommendations and the
15 engineering recommendations of Fossil Generation's equipment/system
16 experts.
17
18 Requests for capital require the initiation of an approved project request that
19 includes a detailed explanation of the project and an initial estimate of cost
20 and benefits. Projects are then further developed for work scope
21 identification and ranked based on economic metrics and other important
22 drivers such as safety requirements, environmental regulations, and outage
23 timing opportunities. Economic evaluation includes a rigorous review of the
24 estimated implementation costs and ongoing benefits. Also included prior to
25 approval is a peer review and challenge process to ensure that all capital

Line No.

1 projects are fully supported by the engineering, strategy and project
2 management teams before projects move ahead in the approval process.
3 This peer review and challenge process focuses on a review of the
4 proposed scope of work to ensure that it 1) represents the best
5 economically viable solution to the problem being addressed and 2) is the
6 least cost method for accomplishing the work proposed.
7
8 Projects are then prioritized for a given budget year and submitted for
9 approval to the Fossil Generation Project Approval Team (PAT), which is
10 comprised of the Fossil Generation Directors.
11
12 Typically, continuing or "carry over" projects from previous years are
13 approved in order to complete their execution. New projects are approved if
14 they are required to meet regulatory requirements related to safety and
15 environmental compliance, or are justified by economics. Specific capital
16 project approval is also driven by the periodic outage schedule since many
17 capital projects are implemented during these longer planned outages in
18 order to minimize the implementation impact on plant availability.
19
20 A certain amount of the Fossil Generation PIP capital budget is held as an
21 "emergent capital" fund available for unforeseen projects that become
22 known during a given year and typically ranges between 5 and 10% of the
23 total capital budget.
24

Line No.

1 In summary, the capital spending and approval process is designed to
2 identify the optimal allocation of capital resources to meet safety and
3 environmental regulations as well as improve overall Fossil Generation
4 performance and costs.
5
6 **Q. Can you explain Exhibit A-9, Schedule B6.1 entitled, "Capital**
7 **Expenditures Steam, Hydraulic, Environmental and Other Power**
8 **Generation and MERC?**
9 A. Exhibit A-9, Schedule B6.1, summarizes Detroit Edison capital expenditures
10 for the time frame of mid-2007 (actual) through mid-2010 (forecasted) for
11 generation facilities. I have identified capital projects as "routine" and "non-
12 routine". A description of the projects and associated expenditure is stated
13 below. My workpaper WPB6.1, further breaks out these projects by the
14 "routine" and "non-routine" categories. The capital expenditures were and
15 will be used to implement projects at the various power plant sites, peaker
16 sites, and Ludington to maintain plant operation, replace aging systems or
17 equipment, increase efficiency and availability and/or address operating and
18 maintenance issues. This schedule also includes planned and historic
19 capital expenditures for major environmental projects required to meet
20 Federal and State regulations. Capital expenditures to maintain ongoing
21 operations at the MERC fuel supply site are also shown. This amount
22 however, is supported by Witness James Good.
23 • Line 2, "Steam Power Generation", includes capital investment in
24 Detroit Edison's fossil steam power plant sites. Included are projects
25 related to Safety, Minor Environmental, Boiler and Turbine, Cables and

Line No.

1 Controls and Balance of Plant Projects. Safety includes those capital
2 expenditures necessary to maintain a safe work environment and meet
3 applicable safety standards. Minor Environmental capital is related to
4 expenditures necessary to satisfy stricter regulations covering air,
5 water, noise and waste disposal regulations mandated by federal, state
6 and local governments. Included in this section are the ongoing
7 replacements of the Selective Catalytic Reduction (SCR) catalyst beds
8 required to meet Nitrogen Oxide reduction requirements with
9 equipment currently installed on Monroe Units 1, 3 and 4. Capital
10 expenditures required to install major new systems to reduce plant
11 emissions covered by the Clean Air Act will be discussed in a later
12 section. Boiler and Turbine, includes those capital expenditures
13 intended to improve boiler or turbine operation, replace unreliable
14 systems or equipment, increase efficiency or availability and/or
15 address operating and maintenance problems related to the boiler and
16 turbine systems. Examples of these projects include proactive
17 replacement of turbine blades, air heater baskets, and boiler tube
18 sections including waterwalls, reheaters, superheaters and
19 economizers resulting from the Boiler Tube Failure Reduction team's
20 identification of the critical need to improve boiler reliability. Cables
21 and Controls, includes those capital expenditures intended to install or
22 improve distributed control systems, replace large power cables, main
23 unit transformers, and electrical switchgear. Balance of plant, includes
24 those capital expenditures for mobile equipment, station air

Line No.

1 compressors, general service water systems, fuel handling equipment
2 and systems, and plant vehicles and computers.

3 • Line 7, "Hydraulic Production Plant", includes those capital
4 expenditures necessary to operate and maintain the Ludington
5 Pumped Storage Facility of which Detroit Edison has a 49 percent
6 ownership stake. These expenditures also include early engineering
7 development of a planned upgrade to the Ludington power output
8 capacity and operating efficiency as proposed and managed by
9 Consumers Energy.

10 • Line 12, "Other Production Plant", includes those capital expenditures
11 related to maintaining peaker site operations as well as upgrading
12 control systems on that equipment to meet and capture value in the
13 upcoming MISO ancillary services market.

14 • Line 17, "Environmental", includes those capital expenditures intended
15 to install major environmental control equipment to comply with Clean
16 Air Act and State of Michigan mercury control rules. Detroit Edison is
17 required to comply with the Nitrogen Oxides (NO_x), Sulfur Dioxide
18 (SO_2), and mercury (Hg) emission reduction requirements of the NO_x
19 State Implementation Plan (SIP) Call developed from 1998 through
20 2003, the Clean Air Interstate Rule (CAIR) issued in 2005, and the
21 Clean Air Mercury Rule (CAMR), also issued in 2005. Additionally the
22 Company is completing engineering and material procurement plans
23 associated with installation of additional emission control equipment in
24 2012 – 2014.

Line No.

- Line 23 and 24, "MERC" and Fuel Supply includes capital expenditures associated with operating and maintaining the MERC transshipment facility for economic delivery of low cost western coal to Detroit Edison's power plants for the benefit of our customers and capital associated with Edison's Fuel Supply organization. These amounts are supported by Witness Good.
- Line 27, "Grand Total", is the sum of the capital expenditures from the five major areas of expenditures.

Q. What were Fossil Generation's Capital Expenditures for July 2007 - June 2008 for Steam Production Plant?

A. During 2007/2008 Fossil Generation capital investment equaled $137 million in steam electric plants. Major investments included:

- $16.6 million to replace the secondary superheater and $6.7 million to replace waterwall tubes on Monroe Unit 4. $5.1 million to replace waterwall tubes on Monroe Unit 2. $5.4 million to replace the secondary superheater pendants and $4.4 million to replace waterwall tube sections on Belle River Unit 2. These replacements are proactively addressing high potential failure areas forecasted by the Boiler Tube Failure Reduction team. Additional proactive boiler tube replacement plans have been developed for the pendant reheaters at Monroe where material and fabrication shop time have been contracted for the four Monroe units over the next five years, with $2.7 million spent on this issue through mid-2008. A total of $40.7 million of

Line No.

1 capital investment was dedicated to boiler tube issues during this time
2 period.

3 • $15.2 million to replace and refurbish turbine valves on Belle River Unit
4 2 and St. Clair Unit 7. Generator exciter replacement on Belle River
5 Unit 1 to convert to a static excitation system that is inherently more
6 reliable than the older technology rotating exciter systems.
7 Replacement of turbine blades on Harbor Beach and the Intermediate
8 Pressure section of Monroe Unit 4. Generator retaining rings were
9 also replaced on Monroe Unit 4 and both Harbor Beach generators.

10 • $8 million to fund the procurement of the Main Unit Transformer (MUT)
11 that was obtained from Consumers Energy, and used to replace the
12 failed equipment from Belle River Unit 1 in 2006. $9.4 million was
13 spent to procure an additional fleet spare MUT and utilized across the
14 Detroit Edison fleet to ensure a ready spare for this critical long
15 procurement/delivery time equipment.

16 • $10.6 million for safety and environmental work on the coal conveyor
17 gallery that traverses M-29 between the Belle River and St. Clair
18 Power Plant sites, Belle River Range Road fly ash site drainage, SCR
19 catalyst installation on Monroe Unit 4 and flue gas stack integrity
20 issues on Monroe Units 3 and 4.

21 • $1.5 million to re-tube the Conners Creek Unit 15 condenser in order to
22 allow more summer megawatt output from this generation unit which is
23 operated to ensure reliability of customer supply.

24 • $10 million to improve plant infrastructure systems with new boiler
25 water treatment equipment for the River Rouge Power Plant, bottom

Line No.

ash handling improvements for Belle River, and coal conveying feeders and Zebra Mussel mitigation systems for the Trenton Channel Power Plant.

- $5.2 million was spent on preparation work for the control system change out on Belle River Unit 1 in the fall of 2008 and on burner equipment on Belle River Unit 2 in the fall of 2007.

Q. What were Fossil Generation's Capital Expenditures for July 2007/June2008 for Hydraulic Production Plant?

A. During 2007/2008 Fossil Generation capital investment equaled $2 million in hydraulic production plants. Major generation investments were related to major unit overhauls and auxiliary equipment upgrades.

Q. What were Fossil Generation's Capital Expenditures for July 2007 - June 2008 for Other Production Plant?

A. During 2007/2008 Fossil Generation capital investment equaled less than $1 million dollars and were mainly associated with control system upgrades.

Q. What were Fossil Generation's Capital Expenditures for July 2007 - June 2008 for Environmental?

A. The Company spent $220.8 million in 2007-2008 for Flue Gas Desulfurization (FGD) and SCR projects at Monroe, NO_x combustion controls for Belle River and Monroe, and mercury monitoring systems. As shown on Exhibit A-9, Schedule B6.1, page 2, this includes $208.4 million for Monroe FGD projects, primarily on Units 3 4, which will go into service in

Line No.

2009. The remaining expenditures of $5.7 million were for SCR projects at Monroe, $3.1 million for NO_x combustion controls at Belle River, and $3.6 million for mercury monitoring systems across the coal-fired units.

Q. What were Fossil Generation's Capital Expenditures for July 2007 - June 2008 for MERC and Fuel Supply?

A. These topics will be covered by Witness Good.

Q. What were and will be Fossil Generation's Capital Expenditures for July 2008 - June 2009 for Steam Production Plant?

A. During 2008/2009 Fossil Generation capital investment equals $215 million in steam electric plants.

- Major investments during this period include: $17.6 to replace the pendant reheater and $7.1 M to replace waterwall tubes on Monroe Unit 1. $6 million to replace waterwall tubes on Monroe Unit 4. $9 million to replace the superheater pendant and platen tubes on St. Clair Unit 6. $8.4 million to replace waterwall tube sections on Belle River Unit 1. $2.2 million for platen waterwall replacement on Harbor Beach. These replacements are proactively addressing high potential failure areas forecasted by the Boiler Tube Failure Reduction team. Additional proactive boiler tube replacement plans have been developed for the pendant reheaters at Monroe where material and fabrication shop time have been contracted where $5 million will be spent in 2008-2009. A total of $63.2 million is anticipated for boiler tube issues during this time period.

Line No.

- $15 million to replace and procure replacement exciters for Belle River Unit 1 and Monroe Unit 2. Turbine valve upgrades on Belle River Unit 1 were completed. A generator rewind of the River Rouge Unit 3 LP generator rotor, the left hand Harbor Beach Generator rotor and reblading of the Belle River Unit 1 high pressure turbine are completed/planned. Procurement of materials and shop time to support a Spring 2010 partial reblading and low pressure turbine rotor repair on Trenton Channel Unit 9 is included in this category.
- $18.4 million to fund the procurement of a replacement Main Unit Transformer (MUT) to be installed on Monroe Unit 4 that testing has shown to have emerging reliability issues. Purchase of a 345 kV spare MUT to ensure redundant spares for this critical equipment that has a greater than one year procurement window.
- $18.5 million for safety work and environmental work. The coal conveyor gallery that traverses M-29 between the Belle River and St. Clair Power Plant sites is completing the floor replacement due to safety issues. Trenton Channel Boilers 16-19 will have their fly ash conditioning systems replaced to enhance precipitator performance. Monroe flyash disposal system improvements to ash conveying systems. Four layers of SCR catalyst will be installed on various Monroe units.
- Control system upgrades totaling $16M have or will be completed on Belle River Unit 1 and preliminary engineering work completed on the Greenwood distributed control system upgrade.

Line No.

- $10.3 million to improve plant infrastructure systems with new boiler water treatment equipment for Trenton Channel Power Plant, bottom ash transport systems at Belle River Power Plant and flue gas stack systems at Monroe Power Plant.
- $24.5 million related to plant efficiency projects, including $4.2 million for flue gas expansion joints at Belle River and Monroe, $8.8 million for new air heater baskets at Monroe to improve heat transfer and boiler efficiency. Additionally $6.4 million will be spent on St. Clair Unit 6 for improved coal mill feeders, new coal burner modules and fan control systems, all improving combustion efficiency. Belle River Unit 1 has had water based "hydrojet" furnace wall cleaning devices installed to reduce furnace slagging and fouling improving reliability and efficiency. Similarly, Trenton Channel Power Plant Unit 7 condenser will be retubed to improve unit reliability and efficiency.
- A new project that will create major benefits in the future is a conversion of Monroe Unit 3 to burn significantly increased levels of low cost western coals. This project called the "Monroe Coal Blend Enhancement Plan". $4.7 million is being spent on engineering and long lead material procurement to allow this project to be completed in early 2011. The total project estimate currently stands at $75 million. When completed and proven on Monroe Unit 3 the other Monroe Units will be scheduled for similar conversions in later years.

Q. What were and will be Fossil Generation's Capital Expenditures for July 2008 – June 2009 for Hydraulic Production Plant?

Line No.

1 A. During 2008/2009 Fossil Generation capital investment has or will equal
2 $7.2 million in hydraulic production plants. These monies represent Detroit
3 Edison's 49% ownership share of work completed on the Ludington site by
4 Consumers Energy.
5
6 **Q. What were and will be Fossil Generation's Capital Expenditures for**
7 **July 2008 – June 2009 for Other Production Plant?**
8 A. During 2008/2009 Fossil Generation capital investment is approximately
9 $1.3 million dollars
10
11 **Q. What were and will be Fossil Generation's Capital Expenditures for**
12 **July 2008 – June 2009 for Environmental?**
13 A. During 2008/2009 Fossil Generation capital investment has and will equal
14 approximately $215 million in environmental systems. As reflected on
15 Exhibit A-9, Schedule B6.1, page 2, major investments include $181.4
16 million for FGD systems and $14.7 million for SCR equipment at Monroe,
17 $12.7 million for Belle River NO_x combustion controls, and $4.3 million for
18 mercury monitoring systems.
19
20 **Q. What were and will be Fossil Generation's Capital Expenditures for**
21 **July 2008 – June 2009 for MERC and Fuel Supply?**
22 A. This topic will be covered by Witness Good.
23
24 **Q. Can you explain the projected period July 2009 – June 2010 capital**
25 **expenditures for Steam Production Plant?**

Line No.

1 A. A large portion of the projected capital investment for this period is in the
2 Boiler and Turbine area and is prudent based on the age of Detroit
3 Edison's generation portfolio, the condition of these components, and the
4 work identified and prioritized by the Boiler Tube Failure Reduction team.
5 For steam power generation the planned 2009/2010 capital investment is
6 $185.6 million with $28.6 million of that dedicated to the Monroe Coal
7 Blend Enhancement Plan.
8
9 Examples of the major capital projects are:
10 • $15.4 million for replacement of the Monroe Unit 2 high temperature
11 reheater pendant tubes, $14.5 million to replace the economizer on
12 Monroe Unit 2, $8.5 million for waterwall tube replacements on Belle
13 River Unit 2, $2.7 million for radiant superheater tubes on River Rouge
14 Unit 3, $6 million for waterwall tube replacements on St. Clair Unit 7
15 and $5.8 million for replacement of bullnose waterwall tubes on
16 Trenton Channel Unit 9. All of these projects proactively address high
17 potential failure areas forecasted by the Boiler Tube Failure Reduction
18 team and over this time period are projected at an approximately $52.9
19 million investment in boiler reliability.
20 • Environmental compliance driven projects are scheduled to equal $15
21 million and include the following: $13 million for precipitator section
22 refurbishment and ductwork replacements on St. Clair Unit 7 and $2
23 million for fly ash transport piping upgrades at Monroe.
24 • Boiler efficiency project investments of $28.1 million are planned
25 including $14.2 million to add new technology furnace cleaning devices

Line No.

on Belle River Unit 2 and St. Clair Unit 7, $4.9 million to retube the main unit condensers on St. Clair Unit 1, St. Clair Unit 2 and River Rouge Unit 3, $2.3 million for flue gas expansion joint replacements on Belle River Unit 2 and St. Clair Unit 7, $2.6 million for multiple feedwater heater replacements on St. Clair Unit 7, and $4.1 million for other combustion improvement projects on St. Clair Unit 7.

- A $16.4 million investment to reblade turbine rotors, rewind generators and to replace rotating exciters with higher reliability static exciter technology.
- The Monroe Fuel Blend Enhancement plan will undergo a major investment of $28.6 million as this project is ramped up to support the Spring 2011 periodic outage where the new technology installation will be completed. These installations are in the areas of furnace cleaning devices, coal mill enhancements, increased primary air flow, and coal yard improvements to handle increased tonnages of western coal in a safe and environmentally compliant manner.

Q. What will be Fossil Generation's Capital Expenditures for the projected period July 2009 - June 2010 for Hydraulic Production Plant?

A. During 2009/2010 Fossil Generation capital investment will be approximately $4.5 million in hydraulic production plants. Included in this investment level is the preliminary work on a major capacity and efficiency project planned for the Ludington Units. Modifications are planned which will increase the rated capacity of each Ludington generator by 23 MW while increasing both pumping and generating efficiency.

Line No.

1

2 **Q. What will be Fossil Generation's Capital Expenditures for the projected**
3 **period July 2009 - June 2010 for Other Production Plant?**
4 A. During 2009/2010 Fossil Generation capital investment will equal $1.7
5 million dollars in this area.
6
7 **Q. What will be Fossil Generation's Capital Expenditures for the projected**
8 **period July 2009 - June 2010 for Environmental?**
9 A. During 2009/2010 Fossil Generation projects $173.4 million of capital
10 investment in environmental systems. This investment is primarily related to
11 FGD projects where $154.0 million will be spent at Monroe, including $108.7
12 million for Units 1 and 2 FGDs which are scheduled to go into service in
13 2012 and 2013.
14
15 **Q. What will be Fossil Generation's Capital Expenditures for the projected**
16 **period July 2009 - June 2010 for MERC and Fuel Supply?**
17 A. This topic will be covered by Witness Good.
18
19 **Part III**
20 **Operating and Maintenance Expenses**
21 **Q. Can you explain the process used to prepare the Fossil Generation**
22 **Operating and Maintenance budget?**
23 A. Individual plant Operating and Maintenance (O&M) budget proposals are
24 developed by taking historical O&M expenditure data and adjusting for any
25 projected period changes. Plant level changes include inflation, year-over-

Line No.

1 year variations in periodic outage work, cost increases related to
2 environmental equipment operation, non-periodic maintenance cost
3 variations driven by predictive maintenance programs and other known
4 changes.
5
6 The overall Fossil Generation O&M projection is then developed by
7 aggregating the plant specific projections, adding the forecasted O&M costs
8 associated with various support organizations, and comparing to the
9 organizational budget guidelines developed at the corporate level. In doing
10 so, a peer review and challenge process ensures that all O&M expenses
11 are fully reviewed and supported by plant, engineering, and staff groups
12 before final approval.
13
14 **Q. What were Fossil Generation's O&M Expenditures for July 2007 / June**
15 **2008?**
16 A. Exhibit A-10, Schedule C5.1 provides a summary of Power Generation
17 (excluding the Fermi plant) O&M expenses for mid- 2007 (actual) through a
18 projected forecast for July 2009 – June 2010 projected period. During
19 2007/2008, Fossil Generation O&M expenses totaled $324.6 million dollars.
20 This was comprised of $141.6 million in costs associated with Fossil
21 Operations and $183 million in costs associated with Fossil Maintenance.
22
23 Fossil Operations expenses are those associated with day-to-day operation
24 of the generating units, including certain Account 501 fuel handling
25 expenses.

Line No.

1

2 Fossil Maintenance expenses are associated with periodic and non-periodic
3 outage activities. Non-periodic outage activity reflects standard "day-to-day"
4 work that is done to maintain plant equipment. This includes inspections,
5 servicing, and minor maintenance that does not require the unit to be taken
6 offline to complete as well as expenses associated with forced outages and
7 de-rates.

8

9 **Q. Can you provide additional detail on the major expense categories**
10 **found in Exhibit A-10, Schedule C5.1?**
11 A. Schedule C5.1 contains detail of the major O&M expenses incurred for
12 Steam Power Generation equipment during the historical period of July 1,
13 2007 through June 30, 2008 and adjustments to bridge the gap from the
14 historic to the test period interval. The expenses are broken down into the
15 major categories of operations and maintenance as required by FERC
16 accounting guidelines.

17

18 Operations account 500 includes the cost of plant management for the
19 individual plant sites and their supporting staffs. Plant management
20 includes plant site director, area managers and administrative support. The
21 major supporting staffs in this area are the technical and engineering
22 personnel associated with problem solving daily plant operating issues,
23 obtaining and interpreting test data and developing long term operating and
24 investment plans to improve plant availability and efficiency.

25

Line No.

Operations account 501 “Fuel” includes expenses incurred for coal train and vessel unloading, ash disposal, coal pile management and mobile equipment operations and fuel expenses. Depending on plant site and delivery options, plants maintain and manage a coal pile inventory that can vary over many months. The longer time frame is required to ensure adequate fuel supplies when vessel deliveries cannot be obtained due to winter ice on the Great Lakes.

Accounts 502 and 505 represent operations personnel expenses associated with direct operating supervision and control of boiler, turbine, generator and water systems. Shift supervisor and control room supervising operators are key to the successful steam power generation unit operations that are required to ensure adequate and cost efficient production of electrical energy for our customers. Their labor expenses are captured in this account.

Account 506 “Misc Steam Power Expense” includes Instrument and Controls personnel to troubleshoot and calibrate that vast array of complex instruments and controls found on all modern steam generating units. Also included in this account are operations of all common equipment of the boiler, turbine, water, air and cooling equipment systems. Plant buildings and grounds cleaning, landscaping, snow removal and maintenance are also captured in this account.

Line No.

1 Maintenance accounts 510 through 514 capture expenses associated with
2 planned and unplanned maintenance activities. The major area being the
3 planned major maintenance activities that generally occur on a two to five
4 year interval on all boiler systems and on a five to ten year interval on
5 turbine – generator systems.
6
7 Account 510 captures management of the plant maintenance area including
8 area managers and general foreman. Account 511 covers maintenance of
9 buildings and structures such as roofs, windows and roads.
10
11 The major area of expense captured in account 512 "Maintenance of
12 Boilers" includes expenses for internal and external labor and all materials
13 associated with planned and unplanned outage work on the boilers. The
14 boiler maintenance scope of work includes the boilers, air and flue gas
15 systems, ash handling and fuel burning equipment. Since outage intervals
16 are cyclic, individual units and plants will see varying expenses over the
17 years. However, with the Company's large fleet of units, maintenance
18 activities are planned and work scope requirements levelized so that the
19 year-to-year variations in maintenance expenses are relatively stable.
20
21 In the historic period of July 2007 through June 2008 the Company
22 executed planned periodic maintenance outages with durations of three to
23 ten weeks on eight major steam generating units. Belle River Unit 2 and
24 Monroe Unit 4 completed major outages of approximately 10 weeks each
25 while St. Clair Unit 3, St. Clair Unit 4, Monroe Unit 2, River Rouge Unit 2

Line No.

1 and Trenton Boilers 16-19 completed shorter duration major outages. Also
2 completed during this time period was one week or less short duration
3 furnace cleaning outages on the St. Clair and Belle River Units to allow their
4 continued efficient operation burning 100 percent or very high percentages
5 of lower cost, cleaner western coals.
6
7 During the test year of July 2009 through June 2010 the Company will
8 execute three major periodic outages of eight to ten weeks in duration on
9 Monroe Unit 2, St. Clair Unit 7 and Trenton Channel Unit 9. Shorter
10 duration periodic outages will also be completed on St. Clair Units 1 and 2,
11 Monroe Unit 3 and Belle River Unit 2. As in the historic period, short
12 duration furnace cleaning outages will also be completed on the St. Clair
13 and Belle River Units.
14
15 The other category of major maintenance expenses incurred during the
16 historic period was associated with normal plant maintenance while units
17 were in operation or expenses to repair or replace equipment during a
18 forced or unplanned unit outage. These short duration unplanned outages
19 can generally be completed in three to seven days and will be experienced
20 at varying intervals on all steam power generating units depending on
21 severity of their service cycles and the time elapsed since their last planned
22 maintenance outage.
23
24 **Q. What projections are included in the Fossil Generation O&M forecast**
25 **from July 2008 to August 2010?**

Line No.

1 A. Over the next two year period expenses are projected to rise by the rate of
2 inflation. These inflation rates were provided to me by Witness Sherrie
3 Siefman. As indicated above, another major driver of changes in Fossil
4 Generation O&M are the costs associated with operation of new
5 environmental equipment combined with additional operation of existing
6 environmental equipment. Specific items in this area are listed below and
7 detailed in my Workpaper WPC5.1, Support Schedules 2 and 3:
8 • Year round operation of the SCR's on the three units where this
9 equipment is installed at Monroe Power Plant is projected to increase
10 in yearly expense of $5.2 million.
11 • Operations of new FGD on Monroe Units 3 and Unit 4 starting in 2009
12 will increase the test year O&M expenses by $9.6 million
13
14 Another major driver of changes in Fossil Generation O&M is the positive
15 impact of Edison's Performance Excellence Process achieved during the
16 historic period. Examples of these savings include:
17 • Non–Labor O & M savings that include Supply Chain initiatives to
18 reduce the costs of goods purchased through process streamlining,
19 contract leveraging across the fleet, improved demand management of
20 supplies, strategic sourcing of on-going maintenance repair and
21 operational (MRO) activities, and increased scrutiny of costs
22 associated with operating and maintaining the Fossil Generation
23 vehicle fleet, including mobile equipment such as bulldozers and
24 scrapers.

Line No.

- Front-Line Productivity O&M savings associated with improved utilization of the existing workforce and selected reduction of this workforce through attrition. These savings will be enabled through: 1) certain capital projects such as water treatment system improvements, hand held data loggers, and Belle River fuel handling cascade chutes; 2) the identification and elimination of process waste by, for example, improved tool and equipment staging; and 3) the improvement of manpower effectiveness through other maintenance productivity improvements, operator rounds optimization, and fuel supply process streamlining. By doing this, Fossil Generation is able to absorb the natural attrition of manpower and/or use the existing Detroit Edison workforce to complete jobs which have traditionally been contracted.
- Non-Represented O&M savings are associated with reductions in supervisory and technical personnel, both in the plants and in centralized support groups. These reductions have been enabled by a thorough examination of work process activities, and the resulting alignment of the non-represented workforce to the most value-added activities.
- Periodic Outage O&M savings will be realized through many of the same processes discussed above (strategic sourcing, demand management, wrench time improvements, equipment staging, displacing contractors, etc.), that are concerted efforts to drive improvement within the duration of a scheduled unit maintenance outage without impacting completion of the defined work scope.

Line No.

1 **Q. Can you summarize Exhibit A-10, Schedule C5.3 Projected Operations**
2 **and Maintenance Expenses for Hydraulic Power Generation?**
3 A. Exhibit A-10, Schedule C5.3, represents Detroit Edison's obligation towards
4 the continuing operation and maintenance of the Ludington Pumped
5 Storage facility. As a 49 percent owner of this facility the Company has and
6 will owe these monies to Consumers Energy Company as defined by our
7 contact with them.
8
9 **Q. Can you summarize Exhibit A-10, Schedule C5.4 Projected Operations**
10 **and Maintenance Expenses for Other Power Generation?**
11 A. Exhibit A-10, Schedule C5.3, represents Detroit Edison's peaker fleet O&M
12 costs. Detroit Edison owns and operates 85 peaking units ranging from 2.5
13 MW diesel fuel engines to newer 85 MW natural gas fired combustion
14 turbines.
15
16 **Q. Can you summarize the level of Fossil Generation's overall O & M**
17 **expenses from 2007 through 2010?**
18 A. As discussed more specifically above, Fossil Generation spent a total
19 $324.6 million in overall O&M during July 2007 through June 2008. Over
20 the next two year period those expenses are projected to rise only by the
21 rate of inflation. During this same period Fossil Generation is projecting
22 increased O&M costs associated with new and existing environmental
23 control equipment, mainly located at Monroe Power Plant. To maintain the
24 Fossil Generation projected O&M expenditures at the inflation rate for the
25 period July 2008 through July 2010 is only possible due to aggressive cost

Line No.

1 containment and process improvements ongoing and planned within Fossil
2 Generation.
3
4 **Q. What are your thoughts concerning the level of Detroit Edison's**
5 **historical and projected capital and O&M expenses contained in your**
6 **testimony?**
7 A. Detroit Edison has been reasonable and prudent in past capital and O & M
8 expenditures as well as for such expenditures in 2009 and beyond.
9
10 During this same time frame, generation unit availability is forecasted to
11 increase through a rigorous process that continues to be focused on
12 prudent capital and O&M investment. All in all, I believe that Detroit Edison
13 has fully justified its request for recovery of the fossil generation plant
14 expenses that are set forth in my testimony and associated Exhibits.
15
16 **Q. Does this complete your testimony?**
17 A. Yes, it does.

Exhibit 2-I

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
ENFORCEMENT AND
COMPLIANCE ASSURANCE

Michael Solo, Esq.
DTE Energy
One Energy Plaza
Detroit, MI 48226-1279

MAY 28 2010

Re: *Monroe Unit 2 Capital Improvement Projects*

Dear Mr. Solo:

The United States Environmental Protection Agency ("EPA") has learned of information suggesting that DTE Energy ("DTE") is currently performing a number of capital improvement projects at unit 2 of the Monroe Power Plant. We have evidence indicating that these projects constitute modification(s) under the New Source Review ("NSR") provisions of the Clean Air Act, 42 U.S.C. § 7401, *et. seq.*, and the corresponding provisions of the Michigan State Implementation Plan ("SIP"). *See, e.g.*, Attachments A (March 12, 2010 K. Guertin Letter to W. Presson) ("Notice Letter") and B ("Extreme Makeover: Power Plant Edition," Monroe Evening News, April 22, 2010).

Please provide the information below by close of business on June 1, 2010.

As you know, it is illegal to modify an existing source of emissions without, *inter alia*, obtaining a permit and installing pollution controls. The seriousness of the violation would be compounded by beginning operation of the illegally modified unit. U.S. EPA is charged with enforcement of the Clean Air Act, *e.g.*, 42 U.S.C. § 7413, and has the authority to "take such measures, including issuance of an order, or seeking injunctive relief, as necessary to prevent the construction or modification of a major emitting facility which does not conform to the requirements of this part." 42 U.S.C. § 7477. EPA also has the authority to obtain information from owners and operations of emissions sources. 42 U.S.C. § 7414.

DTE has provided information to state regulators that it is currently performing capital projects, including the replacement of the economizer and the high temperature reheater pendant, at Monroe unit 2. The information provided indicates that the project will last until mid-June. In its Notice Letter, DTE projects emissions increases of 3,701 tons of SO_2, 4,096 tons of NO_X, and 615 tons of PM compared to the baseline periods selected by the company. DTE has provided no information that these emissions increases can be excluded as caused solely by demand

growth. Under the rules, for an applicant to exclude any portion of an emissions increase, it must demonstrate *both* (i) that those emissions "could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions" *and* (ii) that those emissions are "unrelated to the particular project." MAR 1801(ll)(2)(C).

Given that DTE may soon complete its modification of Monroe Unit 2, time is of the essence. Pursuant to Section 114, please provide the following information by the close of business on **June 1, 2010**:

- When currently DTE expects to complete the outage at unit 2; and
- Any additional information that you believe supports your contention that the work done during this outage does *not* require a permit.

Sincerely,

Phillip A. Brooks
Director, Air Enforcement Division

Exhibit 2-J

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
ENFORCEMENT AND
COMPLIANCE ASSURANCE

Michael Solo, Esq.
DTE Energy
One Energy Plaza
Detroit, MI 48226-1279

JUN - 4 2010

Re: *Monroe Unit 2 Capital Improvement Projects*

Dear Mr. Solo:

The United States Environmental Protection Agency ("EPA") has determined that DTE Energy Co. and/or Detroit Edison (collectively "DTE") is currently performing or has performed a number of capital improvement projects at unit 2 of the Monroe Power Plant. DTE have begun actual construction of (and continue to construct) a boiler rehabilitation project that constitutes a "major modification" under the Act at the Monroe Generating Station Unit 2 ("Monroe Unit 2") without complying with Part C of the Act, 42 U.S.C. §§ 7470–7492, and the federally-approved State Implementation Plan ("SIP") regulations at Michigan Admin. Code R. 336.2801 to 336.2830. Under the Act and implementing regulations, DTE was required to, among other things; obtain a Prevention of Significant Deterioration ("PSD") permit prior to beginning actual construction. DTE's failure to do so constitutes a violation of the Act and the Michigan SIP. A notice of violation is attached.

As you know, it is illegal to modify an existing source of emissions without, *inter alia,* obtaining a permit and installing pollution controls. The seriousness of the violation would be compounded by beginning operation of the illegally modified unit. U.S. EPA is charged with enforcement of the Clean Air Act, *e.g.*, 42 U.S.C. § 7413, and has the authority to "take such measures, including issuance of an order, or seeking injunctive relief, as necessary to prevent the construction or modification of a major emitting facility which does not conform to the requirements of this part." 42 U.S.C. § 7477.

Please provide all documents (including electronic documents) for the PROMOD run used in the DTE September 2009 PSCR filing, including, but not limited to (i) input and output data specifically identified as such, (ii) settings information; (iii) all information necessary to run the PROMOD simulation, (iv) information describing current conditions, and (v) any explanatory materials related to the operation of the model (including instructions and user guides), and (vi) documents relating to the development or discussion of input values related to availability or outage rates used in the model run. This includes, but is not limited to all

associated files, notes, memoranda, and reports. All data inputs necessary to replicate the PROMOD run should be produced in an electronic format suitable for loading into the PROMOD program. All data files associated with this run, regardless of whether the use is directly related to the version of the model run or output provided to the Michigan Public Service Commission must be provided.

Please provide all computer files in an electronic, readily accessible format, as well as in hard copy. If you have any questions about how to provide the material, please contact Mark Palermo, EPA Region 5.

Pursuant to Section 114 of the Clean Air Act, please provide this information as soon as possible and in any event by COB Tuesday, June 15, 2010. If you have any questions, please contact Mark Palermo, EPA Region 5.

Sincerely,

Phillip A. Brooks
Director, Air Enforcement Division

Exhibit 3

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5

IN THE MATTER OF:	)	
	)	
	)	**Proceedings Pursuant to:**
DTE Energy Company	)	**Section 167 of the Clean Air Act,**
Detroit, Michigan	)	**42 U.S.C. §7477**
	)	
	)	
	)	
	)	
	)	

DECLARATION OF
RANAJIT (RON) SAHU

(1) I, Ranajit Sahu, am an environmental engineer with more than 18 years of experience in program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; and multimedia environmental regulatory compliance and permitting, among other things. In addition to my consulting work for private industry on New Source Review and other matters, I have testified on behalf of the United States in seven New Source Review enforcement actions in federal court. In several of those cases, I performed emissions calculations using the same method I use here.

(2) I have a B.S., M.S., and Ph.D. in Mechanical Engineering, the first from the Indian Institute of Technology (Kharagpur, India) and the latter two from the California Institute of Technology (Caltech) in Pasadena, California. My research specialization was in the combustion of coal and, among other things, understanding air pollution aspects of coal combustion in power plants.

(3) I have been asked to assess a potential modification under the Clean Air Act of New Source Review (NSR) and especially the Prevention of Significant Deterioration Program (PSD) there under at Monroe Unit 2. This boiler modification project includes, among many other things, replacement of the economizer, high temperature reheat pendants, and a portion of the waterwalls.

(4) In the event that I determine that a potential modification under PSD may have occurred, I have been asked to provide an opinion on what emissions reductions would result under the Best Available Control Technology (BACT) for NO_X and SO_2 for Monroe Unit 2. And, what the "excess" emissions would be from Monroe Unit 2 if BACT is not used. Finally, I have been asked to provide an opinion on what DTE could do to mitigate such excess emissions.

(5) This declaration contains my opinions, conclusions, and the reasons therefore on the subjects that I was asked to address. The body of the declaration and appendices list the data and other information considered in forming these opinions. Exhibits and tables in summary of, or support of, these opinions are included with this declaration. Appendix A provides a statement of my qualifications. Appendix B provides a list of considered documents in addition to those cited in the body of the Declaration. I am being compensated at the rate of $125/hr ($150/hr for deposition and trial testimony).

A. Emissions Increase Calculation

(6) All NSR emissions calculations are done on an annual tons per year basis. The first rule of PSD emissions calculations requires that net increases or decreases in emissions from a modification be quantified or "projected" before the source undertakes such activity.

To do this, the source must quantify actual annual emissions of the relevant pollutant before the project and the predicted annual emissions of the relevant pollutant after the project. These two figures are then compared – i.e., the pre-project actual annual emissions are subtracted from the post-project projected annual emissions to determine if there is a projected increase in annual emissions. The important thing to note is that it is the difference between the post-project and pre-project emissions that is important. The pre-project actual annual emissions are sometimes referred to as the baseline emissions. If this difference in emissions (between future predicted and baseline) exceeds the specified Significant Emissions Rates for the respective pollutant, then NSR is triggered.[1]

(7) In my calculations for this case, I used the baseline periods specified by DTE in its March 12, 2010 letter to the state permitting authority. Thus I used July 2006-June 2008 for SO_2, and October 2006-September 2008 for NO_X. I note that DTE sets forth an incorrect SO_2 emissions rate in its March 12, 2010 letter.[2]

(8) For estimating the emissions difference discussed above, Robert Koppe started with historic information contained in Generating Availability Data System (GADS) data, which is used by DTE and other utilities for reliability reporting, outage planning, and a host of other uses. This data provides a source of likely increased available (and utilizable) generating capacity after each modification, and as such can be used to apply an "Actual to Projected Actual" test called for under the applicable NSR rules. GADS data is considered historical operational data, as referenced in the regulations and the

[1] In certain cases, a source may "net out" of any emissions increase, but DTE has not suggested that netting is applicable here. Netting is raised, if applicable, by the source during the pre-construction period.

[2] Based on DTE data provided to EPA's Acid Rain database for the baseline period, the SO_2 emissions reported were 60,679 tons and the heat input reported was 96,130,130 MMBtu – leading to an average SO_2 emission rate of 1.26 lb/MMBtu.

WEPCO remand and is therefore available to the utility. Thus, using GADS data is fully consistent with the underlying regulatory requirements and is consistent with an Actual to Projected Actual emissions calculation methodology.

(9) I looked at the component-specific GADS availability loss data (in megawatt-hours) for each of the 24-month baseline periods prior to the modification. This data was gathered by Robert Koppe and is explained in his declaration. To simplify matters, we only considered GADs availability loss data for the economizer and pendant reheater – two of the components being replaced. I then directly estimated the annual (tons/yr) emissions for each pollutant (NO_X and SO_2) associated with the corresponding GADs component outage MWhs in each baseline time period. As Mr. Koppe explains, by replacing the worn components, DTE should expect not to have future outages related to those components (i.e., the economizer) in the projection period. Thus the unit will gain hours of availability equal to the component outage hours in the baseline period.

(10) In calculating the post-project increase in emissions, because coal-fired units typically do not run at full power all the time, I assume that the unit will actually generate only a portion of the total full power megawatt-hours recovered by the availability improvement project. I used the unit's output factor for the respective baseline periods for NO_X and SO_2 as provided to me by Mr. Koppe, to adjust the expected heat input reflecting the additional hours of operation. I used DTE's projected emission rates for NO_X and SO_2 in my calculations. Taking the outage hours from the baseline period, I calculated the emissions that would be expected in those hours in the future. Using the method described, I calculated the following emissions increases as a result of the economizer and high-temperature reheater replacement currently being performed at Monroe Unit 2:

for NO_X, an expected net annual increase of 735 tons/year; and for SO_2 an expected net annual increase of 1382 tons/year. My calculation is set forth in Appendix C.

(11) The calculations I have used above are similar to the calculations that I have done for other power plant NSR cases including Ohio Edison, Illinois Power, Duke Power, etc.[3]

(12) These increases are much larger than the significance threshold for NO_X and SO_2 of 40 tons per year. Thus even if there was some dispute about my methodology, there can be little doubt that significant increases under the NSR permitting program should be expected.

(13) For a unit of this size and characteristics, Monroe Unit 2 would only need to run approximately 40 additional hours at full power to produce 40 tons of NO_X and approximately 17 additional hours at full power to produce 40 tons of SO_2. I calculated these additional hours of operation needed to cross the 40 ton "significance" threshold by using the gross MW rating of the unit and the respective emission factors for each of the pollutants that I used in the previous calculations.

(14) In its March 12, 2010 letter to the state providing notice of the project, DTE predicted significant emissions increases for NO_X and SO_2 as a result of the proposed project but then erroneously disregarded these increases as being permissible since they were, in DTE's opinion, capable of being accommodated in the pre-project state of the unit. Not only is this a mis-interpretation of the applicable regulatory requirements, it belies the very reason for implementing these projects – i.e., why invest resources in implementing these projects if the unit could, effectively, run just as well without implementation of the

[3] While the applicable rules were changed somewhat in 2003, our method is consistent with the new regulations.

projects? Given this mis-interpretation, it is my opinion that this letter provides evidence that the proposed projects will result in a significant net emissions increase, thereby triggering PSD.

(15) My conclusions are further supported by DTE sworn testimony before the Michigan Public Service Commission. There Vice President of Fossil Generation Paul Fessler described DTE's efforts to improve plant availability across its coal-fired generating fleet. These efforts confirm that DTE believes that capital projects can increase unit availability and that it is reasonable to conclude that Monroe Unit 2's availability would increase after this project (rather than have any improved availability in the replaced components be overcome by decreased availability elsewhere in the unit).

B. BACT-Level Pollution Controls

(16) Based on the above, I conclude that Monroe Unit 2 would trigger PSD for NO_X and SO_2. Therefore, it is subject to the BACT provisions of the Clean Air Act. BACT for NO_X and SO_2 from coal-fired power plant boilers will generally involve the application of Selective Catalytic Reduction (SCR) for NO_X control and some form of flue gas desulfurization (FGD) for SO_2 control. Recently, the Michigan Department of Natural Resources and the Environment (DNRE) also determined that these technologies are BACT for Monroe Units 3 and 4 (which are sister units to Monroe Unit 2).[4]

(17) I have not conducted a full-blown BACT analysis for Monroe Unit 2 at this time. While I do not necessarily agree with the levels chosen as BACT for NO_X and SO_2 for Monroe

[4] See Michigan DNRE Public Participation Documents for Permit Application Number 93-09, April 13, 2010, pages 18-21.

Units 3 and 4 recently by the Michigan DNRE, I agree that the technologies chosen, namely SCR for NO_X control and FGD for SO_2 control, are capable of BACT emission levels. I note also that levels of NO_X emission of 0.07 lb/MMBtu[5] and SO_2 0.02 lb/MMBtu should be expected since these values are being achieved by Units 3 and 4 now, upon installation of SCR and FGD. I obtained these values from emissions data reported by DTE to EPA's Acid Rain database.

(18) I also note that DTE expected 90% reduction in NO_X emissions by using SCR and 97% reduction for SO_2 emissions using FGD. See DTE Nov. 16, 2009 Press Release.[6] Without delving into what BACT may be, these are conservative values that I will use in my excess emissions analysis below. Monroe Unit 2's actual average NO_X emissions rates (lb/MMBtu) and actual average annual NO_X emissions (tons/year) over the last 5 years – representing typical annual operations - are shown below:

Year	Actual NO_X Emission Rate (lb/MMBtu)	Actual NO_X Emissions (tons/year)	Excess Emissions (tons/yr) using 90% Reduction of NO_X
2005-2009	0.40	8,825	7,942

The table above shows that excess annual NO_X emissions (tons/yr) are 7,942 tons/yr.

[5] I am aware that the state of Michigan, in its permit for Monroe Units 3 and 4 suggested that NO_X BACT for these units is 0.08 lb/MMBtu on a 12-month rolling average even though it recognized that the Units had performed at levels of 0.05 lb/MMBtu . See Michigan DNRE Public Participation Documents for Permit Application Number 93-09, April 13, 2010, pp. 21. I do not believe that NO_X BACT should be 0.08 lb/MMBtu for Unit 2.

[6] A true and correct copy of this press release is attached to this declaration.

(19) I have done a similar analysis for SO_2 emissions below, using DTE's expectation that the FGD will reduce emissions by 97%. See DTE Nov. 16, 2009 Press Release. I note that the Michigan DNRE expected that wet FGD emissions reductions can be 99%. Monroe Unit 2's actual average SO_2 emissions rates (lb/MMBtu) and actual average annual SO_2 emissions (tons/year) over the last 5 years – representing typical annual operations - are shown below:

Year	Actual SO_2 Emission Rate (lb/MMBtu)	Actual SO_2 Emissions (tons/year)	Excess Emissions (tons/yr) at 97% Reduction of SO_2
2005-2009	1.24	27,345	26,525

The table above shows that excess annual SO_2 emissions (tons/yr) are 26,525 tons/yr.

(20) If DTE Unit 2 were to install the SCR for NO_X control and wet FGD for SO_2 control, these projects, in my opinion, would require around 3-4 years to be planned, engineered, procured, and installed for the scrubber. DTE intends to install the SCR in 2011.[7] Thus, assuming that Unit 2's operations remain typical as they have been in the 2005-2009 time period, the excess annual emissions I have calculated will be emitted for the coming 4 years, including the time necessary for obtaining the necessary permits. The permitting process would likely cost DTE about $150,000. DTE has publicaly announced that the

[7] See DTE Press Release, December 8, 2009.

ultimate installation of SCR and FGD at Unit 2 would cost approximately $630 million dollars.[8]

C. Short-Term Emissions Reductions

(21) DTE runs several coal fired units within its system. Excluding the Monroe units, these include Belle River Units 1 and 2, Harbor Beach Unit 1, River Rouge Units 3 and 4, St. Clair Units 1 through 7, and Trenton Channel Units 9A and 16-19. Of these, it appears that the Belle River units are comparable in size to the Monroe Units. Somewhat smaller are the Trenton Channel Unit 9A, St. Clair Unit 7, and the River Rouge Units.

(22) In order to mitigate excess emissions from Monroe Unit 2 by reducing emissions at that unit or other coal-fired units in DTE's system, DTE could consider various approaches that will provide emissions reductions in a relatively short time period, including:

(a) *Low sulfur coal.* This will directly reduce SO_2 emissions, without significant capital cost; the time to implement this option would depend on the contractual ability to procure low sulfur coals – it could be as short as a few months. The cost impact would depend on the cost differential between the existing and new coal.

(b) *Dry sorbent injection.* Sorbents such as trona, lime, or limestone can be injected into the gas stream exiting the boiler to adsorb SO_2. While reductions using these approaches will not be as great as FGD, nonetheless they can provide reductions in the range of 30-80%, depending on reagent used, particle size, geometry and implementation at specific units. The time to implement this option would be

[8] See DTE Press Release, December 8, 2009. The scrubber would cost around $300 million and the SCR around $330 million, in line with the costs for the scrubbers and SCRs for the other Monroe units.

around 6 months or so. Using sorbent injection for SO_2 controls will require purchase, storage, and injection of the selected sorbent. Capital costs will depend on facility-specific issues but are not expected to be higher than $5 million. The operating and maintenance (O&M) costs for operating the dry sorbent injection will depend on site specific factors including the degree of emissions reductions required, the sorbent selected, the form and size of the sorbent and any processing required, available plant and delivery infrastructure, etc.

(c) *Selective Non-Catalytic Reduction or SNCR*. While not as efficient as SCR, SNCR can reduce NO_X emissions in the range of 20-40% or even higher. Thus, a 25% reduction of SNCR at its other coal units (not Monroe) would result in substantial, immediate, NO_X emissions reductions. Time frame to implement SNCR can be in the range of 6-9 months. SNCR involves adding ammonia or a similar reducing agent using injectors into the boiler at the proper temperature zone. Additional costs will include costs for ammonia storage, handling, injection as well as process controls. The capital costs will likely not exceed $15/kW for the larger units in DTE's fleet. Like for sorbent injection, operating costs will depend on the design of the system and degree of reduction required.

(d) *Combustion optimization.* These include adaptive controls and neural networks. They have been known to reduce NO_X emissions by 10-15%, with a relatively short implementation time period – around 6-9 months. The cost could be minimal since these technologies also optimize fuel use and reduce unburned carbon, providing cost benefits.

While I have not specifically analyzed whether these pollution controls are feasible at DTE's coal-fired units, they are commonly done in the industry and are likely to work on the company's facilities. These are examples only and there could be other means of offsetting Monroe Unit 2's excess emissions.

(23) The costs for offsetting Monroe Unit 2's excess emissions will vary depending on the strategy(ies) used. To illustrate the rough magnitude of costs of an emissions reduction program that would offset the Monroe Unit 2 excess emissions, I estimate the costs and emissions reductions for the installation of a sorbent injection system and SNCR at Belle River Units 1 and 2 and Trenton Channel Unit 9A. The emissions from these units are reported by DTE to EPA and are publicly available available on the EPA Clean Air Markets Division Database. My cost calculations are set forth in Appendix D.

(24) In 2009, the combined actual NO_X emissions from these three units was 13,070 tons and the combined SO_2 emissions was 45,997 tons. If SNCR and neural networks are implemented for NO_X reduction at these three units, and NO_X was reduced by, say, 25%, the NO_X emissions reduction would be around 3,268 tons/yr. Although not enough by itself to offset the NO_X emissions increase at Monroe Unit 2 discussed above, this reduction is a significant portion of the Monroe Unit 2 excess NO_X emissions. These technologies could be implemented in a period of 6-9 months and at a cost of around $29 million in capital costs and a few million dollars annually in operating costs thereafter. Similarly, if in-duct sorbent injection is used, SO_2 emissions at each of these units could be reduced by around 65% or roughly 29,898 tons/yr, more than offsetting the excess SO_2 emissions from Monroe Unit 2. Further reductions could be obtained by using lower sulfur coal at each unit. The reductions from dry sorbent injection could also be

implemented in the 6-9 month time frame and at an additional capital cost of around $10 million and annual costs of around $13 million per year.

(25) Taken together, these projects could offset 33,166 tons/yr (=3,268+29,898 tons/yr from above) of NO_X and SO_2, a significant portion of the combined NO_X and SO_2 excess emissions (26,525+7,942=34,467 tons/yr) from Monroe Unit 2. This offset can be done for an estimated capital cost of around $39 million and annual costs of around $14 million and in a time period of less than 6-9 months.

(26) I also note that reducing emissions at Monroe Unit 2 will assist DTE with its compliance obligations under other regulations such as the revised CAIR or transport rules recently proposed by the EPA, which set limits on NO_X and SO_2 emissions. Additional mercury reductions and reductions in other pollutants such as acid gases and fine particulate matter will also result from installation of NO_X and SO_2 BACT at Monroe Unit 2.

I declare under penalty of perjury that the foregoing is true and correct.

Ranajit Sahu

Executed on August 3, 2010 in Alhambra, CA

APPENDIX A – RESUME FOR RANAJIT SAHU

RANAJIT (RON) SAHU, Ph.D, QEP, REA I, CEM (Nevada), CPP (SCAQMD)
CONSULTANT
311 North Story Place
Alhambra, CA 91801
Phone: 626-382-0001
e-mail (preferred): sahuron@earthlink.net

EXPERIENCE SUMMARY

Dr. Sahu has over eighteen years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

He has over eighteen years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past seventeen years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

In addition to consulting, Dr. Sahu has taught and continues to teach numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater and at USC (air pollution) and Cal State Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

He has excellent written and verbal communication skills in English.

References and specific project experience are available upon request.

EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, Caltech, Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

"Thermodynamics and Heat Transfer," Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

"Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

"Environmental Risk Assessment," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

"Hazardous Waste Remediation" Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2011.

APPENDIX B

CONSIDERED DOCUMENTS

(1) Letter to Mr. William Presson (Michigan Department of Environmental Quality) from Kelly L. Guertin (DTE Energy Company), March 12, 2010.

(2) Letters from Michael Solo (DTE Energy Company)

a. June 1, 2010.

b. June 3, 2010

(3) "Extreme Makeover: Power Plant Edition," Monroe Evening News, April 22, 2010.

(4) Monroe data and calculations.

(5) Qualifications and Direct Testimony of Paul Fessler (The Detroit Edison Company), MPSC Case No. U-15768, January 2009.

(6) Relevant EPA regulations, regulatory preambles, and guidance documents related to New Source Review.

APPENDIX C

Emissions Calculations

DTE Monroe Unit 2 Emissions Calculations

A. GADS Data (Economizer Outages and Deratings Only) from Mr. Koppe

Event Start Date	Event End Date	Outage Duration (hours)	Derating EFPH	Outage Cause	NOx Baseline Period	SO2 Baseline Period
4/3/2006	4/9/2006	124.8		Economizer tube leak		
4/17/2006	4/19/2006	54.9		Economizer tube leak		
4/22/2007	5/7/2007		11.4	Economizer		
5/7/2007	5/9/2007		1.1	Economizer		
5/9/2007	5/11/2007		2.2	Economizer		
5/11/2007	5/12/2007		1.6	Economizer		
5/12/2007	5/15/2007		2.1	Economizer		
5/15/2007	5/23/2007	205		Economizer		
8/7/2007	8/14/2007		8.1	Economizer		
2/12/2008	2/15/2008	75.9		Economizer		
3/23/2008	4/2/2008	237.3		Economizer		
5/9/2008	5/13/2008	83		Economizer		
6/9/2008	6/14/2008	123		Economizer		
7/31/2008	8/3/2008	68.6		Economizer		
8/27/2008	9/1/2008	115		Economizer		
5/19/2009	5/24/2009	120		Secondary reheater		
9/6/2009	9/10/2009	85.8		Economizer tube leak		
1/25/2010	1/29/2010	113.9		Economizer tube leak		
				Lost Full Power Hours including Outages and Deratings	934.3	750.7
				Lost Full Power Hours including Outages Only	907.8	724.2

B. Plant Characteristics

Gross Generating Capacity =	823	MW	[From: EIA-767]
Net Generating Capacity =	795	MW	[From: DTE Letter Dated March 12, 2010]
2013 Net Generation =	5,748,000	MWhN	[From: DTE Letter Dated March 12, 2010]
2013 Hours Expected =	7,230		[Calc]
2013 Gross Generation =	5,950,445	MWhG	[Calc]
2013 Heat Input =	54,974,000	MMBtu	[From: DTE Letter Dated March 12, 2010]
2013 Heat Rate =	9,239	Btu/kWhG	[Calc]
Utilization Factor =	87.9%		[Calc. Based on DTE Letter Dated June 3, 2010]

Calculation of Utilization Factor (UF) from DTE June 3, 2010 Letter

	2010	2011	2012	2013	2014
Period Hours	8760	8760	8760	8760	8760
Service Hours/Operating Hours	6040	8039	7414	7825	6320
Capacity Factor	0.606	0.819	0.762	0.825	0.69
SH/PH	0.69	0.92	0.85	0.89	0.72
UF = CF/(SH/PH)	0.879	0.892	0.900	0.924	0.956

C. Calculations of Emissions Associated with Lost GADS Hours

IMP: Only Economizer Hours Cobsidered. Economizer is being replaced in 2010 Outage. Did not include water wall hours.

[1] NOx

Baseline	October 2006-September 2008		[From: DTE Letter Dated March 12, 2010, Table 1
GADs MWh Lost During Baseline 2 yrs.	742,769	MWh	[From: Mr. Koppe, see Table above]
Utilization Factor	0.808		[Per Mr. Koppe]
Equivalent Heat Input in 2013 w/UF	5,544,632	MMBtu	[Calc.]
Future Emission Factor	0.53	lb/MMBtu	[From: DTE Letter Dated March 12, 2010, Table 1
Emissions from Lost GADs MWh	1469.33	tons	[Calc.]
Annual emissions from Lost GADs MWh	735	tons/yr	[Calc.]
Nox PSD Significant Emission Rate	40.00	ton/yr	[Regulations]

[2] SO2

Baseline	July 2006-June 2008	[From: DTE Letter Dated March 12, 2010, Table 1	
GADs MWh Lost During Baseline 2 yrs.	596,807	MWh	[From: Mr. Koppe, see Table above]
Utilization Factor	0.815		[Per Mr. Koppe]
Equivalent Heat Input in 2013 w/UF	4,493,648	MMBtu	[Calc.]
Future Emission Factor	1.23	lb/MMBtu	[From: DTE Letter Dated March 12, 2010, Table 1
Emissions from Lost GADs MWh	2763.59	tons	[Calc.]
Annual emissions from Lost GADs MWh	**1382**	tons/yr	[Calc.]
SO2 PSD Significant Emission Rate	40.00	ton/yr	[Regulations]

D. Conclusion.

PSD is triggered for NOx and SO2

APPENDIX D

Cost Calculations

SNCR Cost Calculation

Units	Belle River 1, 2 + Trenton Channel 9A		
Rating		1932	MW
Expected NOx Reduction		25%	
2009 NOx Emissions		13,070	tons/yr
Reduction		3,268	tons/yr
Capital Cost		15	$/kw
Capital Cost Est.	**$**	**28,980,000**	$
NH3 to NO2 ratio		1	molar
Qty. of NH3 Reqd.		4830	tons/yr
Ammonia Cost		200	$/ton
Ammonia Cost	**$**	**966,043**	$/yr

DSI Cost Calculation

Units	Belle River 1, 2 + Trenton Channel 9A		
Rating		1932	MW
2009 Unit Operating Time		24823	hrs/yr
Expected SO2 Reduction		65%	
2009 SO2 Emissions		45997	tons/yr
Reduction		29898	tons/yr
Reagent		Trona	
MW - Trona		226	g/mole
MW - SO2		64	g/mole
Reaction: 2 moles trona for 3 moles SO2			
i.e., mass trona/mass SO2		2.35	
Assumed NSR		0.8	
Trona Qty. Needed		86628	tons/yr
Trona Qty. Needed		3.49	tons/hr
Expected Capital Cost		1000000	$/ton/hr
Capital Cost	**$**	**10,469,468**	$
Trona Cost		150	$/ton
Trona Cost	**$**	**12,994,181**	$/yr

33166 26,525

Exhibit 3A

DTE Energy News Releases

Second Scrubber Continues Downward Emissions Trend at Detroit Edison's Monroe Power Plant

PRNewswire
MONROE, Mich.
(NYSE:DTE)
Nov 16, 2009

MONROE, Mich., Nov. 16 /PRNewswire/ -- For the second time this year, Detroit Edison's Monroe Power Plant has achieved a major reduction in emissions. The second flue gas desulfurization system - or scrubber - began operation today at the coal-fired power plant.

With today's startup of the second scrubber, sulfur dioxide emissions are reduced by about 97 percent and mercury emissions are reduced by 80 to 90 percent from the plant's No. 3 generating unit. Similar reductions were achieved in June on Unit 4 when the first FGD began operation. The Monroe Power Plant consists of four individual generating units.

This is the latest milestone in a decade-long program to install state-of-the-art control equipment and dramatically reduce emissions at the Monroe Power Plant.

"The startup of the second scrubber is another major achievement in an emissions control construction program that began 10 years ago and has cost $1.7 billion," said Ron May, DTE Energy senior vice president, major enterprise projects. "This investment makes a significant improvement to air quality in the region and supports the long-term operation of the Monroe Power Plant, which is a cornerstone of Detroit Edison's generating fleet."

In addition to construction of the two scrubbers, selective catalytic reduction (SCR) systems have been installed on three of the plant's generating units. The SCRs provide 90 percent nitrogen oxide (NOx) reduction per unit.

On Units 3 and 4, where both SCRs and scrubbers are operating, mercury emissions are reduced by 80 to 90 percent due to the interaction of the two systems. The Monroe Power Plant is the first power plant in Michigan with both SCRs and scrubbers.

The systems will help the Monroe Power Plant meet current and expected reductions in federal and state emissions limits said Skiles Boyd, DTE Energy vice president, environmental management and resources. "Even though we didn't know exactly what the emissions limits would be when we began construction 10 years ago, we felt it was in the best interest of our company, our customers and the environment to install state-of-the-art emissions control systems at this important plant," he said.

Boyd said engineering work is under way for construction of the third and fourth scrubbers and the fourth SCR for the Monroe plant. Some site work for those systems is expected to begin next year.

Detroit Edison is an investor-owned electric utility serving 2.2 million customers in Southeastern Michigan and a subsidiary of DTE Energy (NYSE: DTE), a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. Information about DTE Energy is available at www.dteenergy.com.

SOURCE: Detroit Edison

Web site: http://www.dteenergy.com/

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Exhibit 4

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

MAY 23 2000

REPLY TO THE ATTENTION OF
R-19J

Henry Nickel
Counsel for the Detroit Edison Company
Hunton & Williams
1900 K Street, N.W.
Washington D.C. 20006-1109

Dear Mr. Nickel:

I am responding to your request on behalf of the Detroit Edison Company for an applicability determination regarding the proposed replacement and reconfiguration of the high pressure section of two steam turbines at the company's Monroe Power Plant, referred to as the Dense Pack project. Specifically, you requested that the United States Environmental Protection Agency (EPA) determine whether the Dense Pack project at the Monroe Power Plant would be considered a major modification that would subject the project to pollution control requirements under the Prevention of Significant Deterioration (PSD) program.

We have reviewed your original request, dated June 8, 1999, and the supplemental information you submitted on December 10, 1999, and March 16, 2000. We provisionally conclude that the Dense Pack project would not be a major modification. Thus, Detroit Edison may proceed with the project without first obtaining a PSD permit. Although the Dense Pack project would constitute a nonroutine physical change to the facility that might well result in a significant increase in air pollution, Detroit Edison asserts that emissions will not in fact increase due to the construction activity, and EPA has no information to dispute that assertion.

As you know, nonroutine changes of any type, purpose, or magnitude at an electric utility steam generating unit -- ranging from projects to increase production efficiency to even the complete replacement of entire major components -- are excluded from PSD coverage as long as they do not significantly increase emissions from the source. Thus, Detroit Edison has been free to proceed at any time with the Dense Pack project without first obtaining a PSD permit as long as it adheres to its stated intention to not increase emissions as a result of the project. Indeed, EPA encourages the company to proceed with the project on this basis, since it appears to both reduce emissions per unit of output and not increase actual air pollution.

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As you are also aware, under the applicable new source review regulations, in determining if a physical change will result in a significant emissions increase at an electric utility plant, companies may use an "actual" to "representative actual annual emissions" test for emissions from the electric utility steam generating unit, under which a calculation of baseline emissions and a projection of future emissions after the change is needed. Our determination of nonapplicability is provisional because Detroit Edison has not, to our knowledge, provided a calculation of baseline emissions or projected future emissions to the permitting agency, and this should be done prior to the start of construction. The basis for this determination is summarized below and is set forth in full in the enclosed detailed analysis.

In determining whether an activity triggers PSD, the Clean Air Act and EPA's regulations specify a two-step test. The first step is to determine if such activity is a physical or operational change, and if it is, the second step is to determine whether emissions will increase because of the change. The statute admits of no exception from its sweeping scope, but EPA's regulations contain some narrow exceptions to the definition of physical or operational change. In particular, Detroit Edison claims that the Dense Pack project is eligible for the exclusion for routine maintenance, repair, and replacement. The determination of whether a proposed physical change is "routine" is a case-specific determination which takes into consideration the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors. After carefully reviewing all the information you submitted in light of the relevant factors, EPA has determined that the proposed project is not "routine."

The purpose of the Dense Pack project, to significantly enhance the present efficiency of the high pressure section of the steam turbine, signifies that the project is not routine. An upgrade of this nature is markedly different from the frequent, inexpensive, necessary, and incremental maintenance and replacement of deteriorated blades that is commonly practiced in the utility industry. For instance, past blade maintenance and replacement of only the deteriorated blades at Detroit Edison has never increased efficiency over the original design. Accordingly, because increasing turbine efficiency by a total redesign of a major component is a defining feature of the proposed Dense Pack project, it clearly goes significantly beyond both historic turbine work at Detroit Edison, and what would otherwise be considered a regular, customary, or standard undertaking for the purpose of maintaining the existing steam turbine units. The project also goes well beyond routine turbine

maintenance, repair, and replacement activities for the utility industry in general.

The nature and extent of the work in question -- replacement of the entire high pressure sections of the steam turbines for Units 1 and 4 at Monroe -- suggests that the Dense Pack project is not routine. It would result in greater efficiency above the level that can be reached by simply replacing deteriorated blades with ones of the same design and, in addition, will substantially increase efficiency over the original design. Specifically, the Dense Pack upgrade would not only restore the 7 percent of the efficiency rating lost over the years at each unit but would improve the unit's efficiency by an additional 5 percent over its original design capacity. Accordingly, the proposed project represents a significant and major redesign and replacement of the entire high pressure sections of the steam turbines at Units 1 and 4 at the Monroe facility.

The frequency with which utilities have undertaken turbine upgrades like the Dense Pack project also indicates the nonroutine nature of the changes. The information provided by Detroit Edison, regarding past history at the Monroe facility, describes what is characterized as necessary maintenance, repair, and replacement of deteriorated turbine blades approximately every 4 years. During these overhaul periods, it is not uncommon for the company to replace up to several turbine blades at one time. It is common among other utilities to also perform similar turbine maintenance. However, Detroit Edison has not provided any information to suggest that a complete replacement and redesign of the high pressure section of a steam turbine is conducted frequently at Monroe or at any other individual utility. Instead, Detroit Edison relies on its claim that projects "similar" to the Dense Pack project have been performed at a number of utilities. This information does not indicate that the replacement of the high pressure section of the steam turbine is frequent at the typical utility source; to the contrary, the only available information reflects that projects like the Dense Pack project have been performed only one time, if ever, at individual sources.

The cost of the Dense Pack project is significant and tends to indicate that this project is nonroutine. Detroit Edison expects the Dense Pack replacement to cost approximately $6 million for each turbine unit, for a total of $12 million. The EPA has rejected claims of routineness in past cases where the cost was substantially less than this figure. Moreover, Detroit Edison intends to capitalize the entire cost of this project, and EPA

believes that a $12 million project that is 100 percent capital improvement indicates that it is a major undertaking.

Beyond the clearly significant absolute cost of this project, available information suggests that this expenditure far exceeds the cost typically associated with turbine blade maintenance activity. Detroit Edison provided only a summary of the total project costs for past maintenance and inspections at the facility, the total costs of which ranged from less than $1 million to a little more than $6 million. Although Detroit Edison did not provide any detail regarding what specific activities comprise these aggregated amounts, it acknowledges that it spent only $18,700, $33,100, and $7,900 to replace high-pressure rotors in three turbine projects in 1981 and 1982. Further, the project is significantly more costly than simply replacing deteriorated blades today; Detroit Edison acknowledges that the Dense Pack upgrade would cost three times more than its alternative blade repair and replacement project. Accordingly, it appears that the costs associated with the Dense Pack project greatly exceed the amounts spent previously by Detroit Edison or that it would spend presently for the replacement of deteriorated turbine blades or rotors.

For the reasons delineated above, we conclude that the changes proposed by Detroit Edison are not routine. Detroit Edison's submissions do not demonstrate that projects such as the Dense Pack project are frequent, inexpensive, or done for the purpose of maintaining the facility in its present condition. Instead, the source relies on two principal arguments: (1) it claims that this project is less significant in scope than was the activity in question in the 1988 applicability determination for the Wisconsin Electric Power Company (WEPCO); and (2) it alleges that EPA has interpreted the exclusion for routine activity expansively to exempt all projects that do not increase a unit's emission rate. EPA rejects both of these arguments, the former because both EPA and the U.S. Court of Appeals for the Seventh Circuit viewed WEPCO's activity as "far from" routine and thus this attempted comparison to WEPCO is unsuitable, and the latter because it is demonstrably incorrect. The attached analysis addresses these points in significant detail.

When nonroutine physical or operational changes significantly increase emissions to the atmosphere, they are properly characterized as major modifications and are subject to the PSD program. In general, a physical change in the nature of the Dense Pack project, which provides for the more economical production of electricity, would be expected to result in the increased utilization of the affected units, and thus, increased

emissions. Notwithstanding the fact the Monroe units may be high on the dispatch order, the Dense Pack project would allow Detroit Edison to produce electricity more cheaply per unit of output, thereby creating an incentive to run Units 1 and 4 above current levels. Even a small increase over current normal levels in the utilization of the affected units would result in a significant increase in actual emissions of criteria pollutants. For example, in 1997, at the Monroe facility Unit 1 emitted approximately 14,000 tons of nitrogen oxides (NO_x) and 41,000 tons of sulfur dioxide (SO_2), and Unit 2 emitted 12,000 tons of NO_x and 35,000 tons of SO_2. Based on this information, if a one to five percent increase in operation were to result from the Dense Pack project, increases on the order of 160-800 tons of NO_x and 400-2000 tons of SO_2 would occur.

Detroit Edison, however, maintains that emissions will not increase as a result of the Dense Pack project. Specifically, the company contends that representative actual annual emissions following the change will not be greater than its pre-change actual emissions, because the Dense Pack upgrade will not result in increased utilization of the units. As you are aware, the PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a nonroutine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change if the source submits information for 5 years following the change to confirm its pre-change projection. In projecting post-change emissions, Detroit Edison does not have to include that portion of the unit's emissions which could have been accommodated before the change and is unrelated to the change, such as demand growth.

Under the WEPCO rule, Detroit Edison must compute baseline actual emissions and must project the future actual emissions from the modified unit for the 2-year period after the physical change (or another 2-year period that is more representative of normal operation in the unit's modified state). As noted above, Detroit Edison has not provided these figures to verify its projection of no increase in actual emissions, and should submit them to the Michigan Department of Environmental Quality prior to beginning construction. In addition, Detroit Edison must maintain and submit to the permitting agency on an annual basis for a period of at least 5 years (or a longer period not to exceed 10 years, if such a period is more representative of the modified unit's normal post-change operations) from the date the units at the Monroe Plant resume regular operation, information demonstrating that the renovation did not result in a significant emissions

increase. If Detroit Edison fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased as a consequence of the change, it will be required to obtain a PSD permit for the Dense Pack project.

Finally, regardless of whether PSD review is triggered due to the Dense Pack project, Detroit Edison must meet all other applicable federal, state, and local air pollution requirements.

This determination will be final in 30 days unless, during that time, Detroit Edison seeks to confer with or appeal to the Administrator or her designee regarding it. If you have any questions regarding this determination, please contact Laura Hartman, Environmental Engineer, at (312) 353-5703, or Jane Woolums, Associate Regional Counsel, at (312) 886-6720.

Sincerely,

/s/ original signed by
Francis X. Lyons

Francis X. Lyons
Regional Administrator

Enclosure

cc: Peter Marquardt, Esq., Special Counsel
Detroit Edison Company
2000 Second Avenue - 688 WCB
Detroit, Michigan 48336

Russell Harding, Director
Michigan Department of Environmental Quality

ENCLOSURE
DETROIT EDISON APPLICABILITY DETERMINATION
DETAILED ANALYSIS

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I. Introduction

If a company intends to construct a major source or a major modification at a source, that source is required to obtain a major new source review permit before beginning construction. If a source questions whether a change is subject to major new source review, the source can request an applicability determination. In this case, Detroit Edison Company has requested an applicability determination from the United States Environmental Protection Agency (EPA). This analysis outlines EPA's decision on the applicability determination for Detroit Edison's proposed project.

II. Summary of Request and Brief Conclusion

Detroit Edison Company is proposing to replace and reconfigure the high pressure portion of two steam turbines at its Monroe Power Plant. The company refers to this project as the "Dense Pack" project. In general, the Dense Pack project would consist of replacing and reconfiguring all of the blades in the high-pressure section of two turbines to substantially increase plant efficiency and reduce maintenance costs. On June 8, 1999, Henry Nickel, Hunton & Williams, submitted on behalf of Detroit Edison a request that EPA determine whether the Dense Pack project would be a "major modification" to the Monroe source, subject to the Prevention of Significant Deterioration (PSD) requirements of the New Source Review (NSR) program. An activity is a major modification and requires a PSD permit if it constitutes a nonexempt physical or operational change and if it results in a significant net increase in emissions. Detroit Edison claimed that the proposed Dense Pack project at two units in Detroit Edison's Monroe Power Plant would not be a "physical change," as the PSD regulations use that term, but instead would qualify for an exemption from the definition of "physical change" under the exclusion for routine maintenance, repair, and replacement. In the alternative, Detroit Edison maintained that the change would not result in an emissions increase that would trigger PSD.

In a letter dated June 25, 1999, EPA wrote Mr. Nickel acknowledging receipt of the request. In another letter to Mr. Nickel dated July 12, 1999, EPA requested more information regarding the proposed Dense Pack project and Detroit Edison's arguments in order to proceed with the review. On December 10, 1999, Mr. Nickel submitted information in response to EPA's July 12th request. In addition, on March 16, 2000, Detroit Edison submitted another letter, along with additional supporting materials. The following summarizes EPA's review of the proposed Dense Pack project based upon these submissions.

EPA has provisionally determined that PSD would not apply at this time if Detroit Edison were to construct the Dense Pack upgrade as described. The project would entail substantial, infrequently performed, and costly construction for the purpose of increasing the source's generating capacity both beyond its prior design and its current capacity. Accordingly, EPA finds that the upgrade is a "physical change," as that term is used in the Clean Air Act (CAA) and its implementing regulations. The Agency rejects Detroit Edison's claim that the project

qualifies for the exemption for routine maintenance, repair, and replacement, because our analysis of the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, leads us to conclude that the project is not "routine" as EPA has historically interpreted that regulatory term. In addition, because the Dense Pack project will substantially increase the operational and economic efficiency of the Monroe facility, EPA finds that the project provides an incentive to significantly increase utilization, and thus, emissions. Detroit Edison has stated, however, that emissions at the plant will not in fact increase as a result of the Dense Pack upgrade, and EPA has no specific information to dispute that assertion. Accordingly, EPA provisionally accepts Detroit Edison's assertion of no emissions increase. However, to establish that no emissions increase will result and that PSD does not apply, the regulations applicable to electric utility steam generating units call for a calculation of baseline actual emissions and a projection of future actual emissions. Thus, before beginning construction on the project, Detroit Edison should provide this calculation and projection to the permitting agency to affirm its assertion of no emissions increase.

III. Factual Background

A. Current Conditions

Detroit Edison's Monroe Power Plant contains four coal-fired boilers, along with four associated steam turbines. The turbines convert the steam generated in the boilers into electric energy, using a system of blades or buckets to convert the energy stored in the steam from the boilers into mechanical energy. This mechanical energy is then transferred to an electric generator. The Dense Pack project is being proposed for two of the four turbines, Units 1 and 4. Units 1 and 4 began operating in 1971 and 1974, respectively. Both units have nominal ratings of 750 megawatts. Currently, the units at Detroit Edison's Monroe Plant, along with those at its Belle River Power Plant, are very high in the loading order for fossil fuel generation in the Detroit Edison system. Detroit Edison claims that, as a result, it has operated Units 1 and 4 at or near maximum capacity over the past five years. Specifically, between 1995 and 1998, the capacity factors for Unit 1 and Unit 4 have been 82.8%, 62.7%, 87.8%, 83.5%, and 63.0%, 82.2%, 79.6%, 87.4%, respectively.

According to submitted information, Detroit Edison shuts down the electric generating units and performs inspections approximately every four years. In addition to other work on other portions of the facility, Detroit Edison performs necessary maintenance, repair, and replacement of individual deteriorated turbine blades at that time. Historically, the source has not had to repair or replace blades in the high pressure section of the turbines every time it inspected them, but such maintenance, including piecemeal repair or replacement, occurs periodically. Detroit Edison states that these scheduled outages typically last a minimum of six weeks, but does not specify how much of this time is devoted to the repair and replacement of worn blades. In general, repair or replacement of the turbine blades could be to maintain fuel efficiency, reliability, safety, or generating capacity, or to comply with regulatory requirements, insurance company requirements, corporate practices, or other reasons. It appears from

individual inspection reports that maintaining efficiency was the stated reason for most inspections and maintenance.

According to Detroit Edison, the turbines at Units 1 and 4 currently are operating at 7% below their original efficiency ratings due to accumulated deterioration in the high-pressure turbine blades. Replacement of the deteriorated blades with blades of the same design would replace only 2% of the lost efficiency, leaving the units 5% below their original efficiency rating. Detroit Edison estimates the cost of replacing only the currently deteriorated blades to be approximately $2 million per unit. Detroit Edison provided only a summary of the project costs for past maintenance and inspections at the facility, the total costs of which ranged from less than $1 million to a little more than $6 million. Detroit Edison spent $18,700, $33,100, and $7,900 to replace high-pressure rotors in three projects in 1981 and 1982. Detroit Edison has not provided other specific cost information regarding the cost of on-site blade repair and replacement or similar information for the utility industry as a whole.

B. Proposed Dense Pack Project

Detroit Edison is proposing to replace the entire high-pressure sections of two turbines to allow for the use of a new type of turbine blade and to reconfigure the design in order to improve efficiency and reduce maintenance costs. To install the Dense Pack, Detroit Edison must shut down the units. Detroit Edison expects the installation to take approximately 44 days, and plans to complete the installation during the time normally allotted for turbine outages. Installation of the Dense Pack would involve replacement and reconfiguration of blades in the high-pressure sections of the two units, using rotors and casings to support the new blade configuration. In addition, the Dense Pack would use a newer, substantially improved type of blade than is currently in use at the Monroe facility.

As noted above, Detroit Edison states that the high pressure sections of the turbines at Units 1 and 4 are operating at 7% below their original efficiency ratings due to accumulated deterioration in the high-pressure section of the turbines. The Dense Pack project would increase efficiency of the high-pressure sections of the turbines over current levels by 12%, restoring the 7% lost efficiency at the high pressure section and improving the efficiency of the high-pressure section by 5% over the original design. This increased efficiency in the high-pressure sections would increase the overall efficiency of each of the turbines by 4.5%. In addition, the new Dense Pack configuration could reduce efficiency deterioration by 70%. Therefore, Detroit Edison expects the inspections and needed repair or replacements to occur once every 10 years, instead of once every 4 years.

Detroit Edison expects the Dense Pack project to cost approximately $12 million. Detroit Edison plans to capitalize 100% of the cost of the Dense Pack project.

IV. Physical Change/Change in the Method of Operation

Before providing its analysis of whether the Dense Pack project would constitute a physical or operational change, EPA believes it would be useful to review what the statute and regulations require and how they have been applied historically. Thus, the following discussion provides a context for the analysis of the project that follows.

A. Statutory and Regulatory Requirements

1. Overview

Both the CAA and the NSR regulations require a physical or operational change to occur before any particular activity is considered a "modification" which triggers new source requirements. The applicable provisions do not, however, define what constitutes a physical or operational change. EPA historically has acknowledged -- in view of these undefined broad statutory and regulatory terms -- that they could "encompass the most mundane activities at an industrial facility (even the repair or replacement of a single leaky pipe, or a change in the way that pipe is utilized)." 57 Fed. Reg. 32314, 32316 (July 21, 1992). Recognizing that Congress did not intend everything undertaken at a stationary source to be subject to new source requirements, id., EPA has long exempted certain narrow classes of activities from being considered physical or operational changes. Accord Alabama Power Co. v. Costle, 636 F.2d 323, 400 (D.C. Cir. 1980) (although "the term 'modification' is nowhere limited to physical changes exceeding a certain magnitude," EPA possesses the authority to provide exemptions from the definition where they are of de minimis benefit or where administratively necessary). There are several such exclusions, but only one is at issue in the present case[1] – the exclusion for "routine"

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1. Detroit Edison suggests that the Dense Pack replacement project is also exempt from PSD as a pollution control project, see, e.g., 40 C.F.R. § 52.21(b)(2)(iii)(*h*), because the source anticipates that the project will decrease the units' emissions on a per-unit-of-output basis. December 10 Letter at 2; March 16 Letter at 3. This claim is not substantiated in any of Detroit Edison's correspondence with the Agency. Our analysis above accordingly focuses on Detroit Edison's primary claim -- that its activity is routine. At the same time, however, EPA does not want to give the impression that it tacitly agrees with Detroit Edison's claimed exemption; to the contrary, the Dense Pack replacement project does not meet the definition of "pollution control project" in the regulations. See 40 C.F.R. §52.21(b)(2)(iii)(*h*), (b)(32). Moreover, virtually any major capital improvement project at an existing source is designed in part to increase efficiency of production, and this will in turn almost always have the collateral effect of reducing emissions per unit of production, even though it may provide an economic incentive to increase total production, with the net result that actual emissions of air pollution to the atmosphere could increase significantly. There is nothing in the statutory terms or structure or in EPA's regulations which suggests that such major changes should be accorded exempt status under the NSR program. To the contrary, major capital investments in industrial equipment, where they

(continued...)

activity.

2. Scope of Exclusion for Routine Activity

a. Statutory and Regulatory Text

The starting point for analysis of any exemption is the language of the statute and governing regulations. Section 111(a)(4) of the CAA reads as follows:

> The term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

CAA § 111(a)(4). The CAA requires a PSD permit prior to "construction" of a major stationary source of any pollutant for which the area in which the source is located is designated attainment or unclassifiable, id. § 165(a), and it defines "construction" as including modifications (as defined in section 111) to existing facilities. Id. § 169(2)(C). EPA's regulations generally track the statute:

> (2)(i) *Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase. . . .

E.G., 40 C.F.R. §52.21(b)(2).[2] The plain language of these statutory and regulatory requirements

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1. (...continued)
could result in an increase in emissions, appear to be precisely the type of change at an existing source that Congress intended should be subject to PSD and nonattainment area NSR permitting. See Prevention of Significant Deterioration and Nonattainment New Source Review; Proposed Rule, 61 Fed. Reg. 38250, 38262 (July 23, 1996) ("NSR Reform" proposed rulemaking). See also Puerto Rican Cement Co. v. EPA, 889 F.2d 292, 297-98 (1st Cir. 1989) (modification of emissions unit that decreases emissions per unit of output, but may result in sufficient production increase such that actual emissions will increase, is subject to PSD). Conversely, nonroutine and otherwise nonexcluded changes of any type, regardless of whether they are projects such as the Dense Pack intended to increase production efficiency, or even the complete replacement of an entire industrial plant, are excluded from PSD coverage so long as they do not result in significant emissions increases. See infra note 4.

2. In this determination, EPA refers interchangeably to the "PSD" and "NSR" programs. There are multiple sets of PSD and NSR regulations, governing the general (or "minor") program (continued...)

indicates their sweeping scope. Both the CAA and its implementing regulations define "modification" as including any physical or operational change. See 42 U.S.C. § 7411(a)(4), CAA § 111(a)(4); see also, e.g., 40 C.F.R. § 52.21(b)(2)(i). In light of that breadth, any regulatory exemption from the statutory and regulatory requirements should be interpreted in a limited way. See Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901, 908-09 (7th Cir. 1990) ("WEPCO") ("courts considering the modification provisions of NSPS and PSD have assumed that 'any physical change' means precisely that").[3]

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2. (...continued)
and the programs for major sources in attainment and nonattainment areas, and governing those programs where EPA is the permitting authority and those where the state is the permitting authority. For ease of use, this document refers to only the applicable requirements here, 40 C.F.R. § 52.21. Those requirements apply where, as here, the state does not have an approved PSD program in its state implementation plan and the federal PSD program regulations apply instead. See id. § 52.1180. EPA has delegated implementation of the PSD program to Michigan, which issues federal PSD permits on EPA's behalf. See id. § 52.21(u). It bears noting, however, that EPA regulations governing approved PSD programs and NSR programs for nonattainment areas also contain an identically worded exclusion for routine activity. In addition, the regulations governing EPA's new source performance standards (NSPS) contain a similar exemption for routine activity. Accordingly, the discussion below does not differentiate between the two programs, and relies upon relevant NSPS precedents as instructive in the NSR program. See 57 Fed. Reg. at 32316 (noting that physical/operational change step "is largely the same for NSPS and NSR"). The most significant difference between the programs' definition of "physical change" is that the NSR regulations do not require a source to affirmatively seek an applicability determination to be exempt as a routine change, id. at 32332, but the NSPS regulations plainly do. 40 C.F.R. § 60.14(e)(1) (activity is exempt if it is "[m]aintenance, repair, and replacement which the Administrator determines to be routine for a source category"). In all respects relevant to this determination, however, the regulations are identical.

3. There is a rule of law that exclusions from generally applicable regulations should be construed narrowly. See Auer v. Robbins, 519 U.S. 452, 462-63 (1986) (recognizing general rule of construction for regulations); see also O'Neal v. Barrow County, 980 F.2d 674, 677 (11th Cir. 1993) (where statute does not provide for exemption, regulations providing for one should be narrowly construed). Similarly, regulatory provisions should be read in conjunction with the statutes from which they are derived and with other similar provisions. Thus, just as other exclusions from the new source provisions are limited to narrow circumstances, one should read the exclusion for routine activity similarly. See, e.g., 40 C.F.R. §§ 52.21(b)(2)(iii)(*b*)-(*e*) (governing the use of alternative fuels when the source is ordered to do so pursuant to certain federal laws, when the fuel is derived from municipal solid waste, when allowed by existing permit, or when the source was capable of accommodating it before January 6, 1975 and is not prohibited from using it by a subsequent federally enforceable permit term); 52.21(b)(2)(iii)(*g*) (excluding changes in ownership of the stationary source).

The requirement that a source both make a physical or operational change and increase emissions to be considered a modification further suggests that the physical or operational change prong of the test should be broadly construed. The statute grandfathers existing facilities from the expense of state-of-the-art controls, but not permanently. Rather, the CAA effected a balance of concerns; if plants were modified – i.e., physically or operationally changed in a manner that increased emissions – the grandfather status would be lost, and NSR would apply. The requirement that there be a net increase in emissions at a source before a modification is deemed to have occurred, however, makes the grandfather provision potentially quite broad.[4] Indeed, this limitation on the modification rule has been viewed by EPA as open-ended – the grandfather status can be permanent so long as emissions do not increase – and environmental groups have long complained of this NSR "loophole."[5]

It is against that statutory and regulatory backdrop that EPA adopted the exclusion for routine activity. It provides:

> (iii) A physical change or change in the method of operation shall not include:
> *(a)* Routine maintenance, repair, and replacement. . . .

40 C.F.R. § 52.21(b)(2). The text of the routineness exclusion itself conveys the narrowly limited scope of the exemption. Because the regulations provide no definition of "routine," nor does the preamble of the notice promulgating the exclusion contain a discussion that would give the exemption a particular meaning for the NSR program, the regulatory term should be used in its ordinary sense. Webster's defines "routine" as "of a commonplace or repetitious character"; "of, relating to, or being in accordance with established procedure." These definitions suggest that determining routineness appropriately involves considering whether the activity is frequent (is it "repetitious"), whether it is of significant scope (is it "commonplace"), and whether it is for a customary purpose or is being accomplished in a customary fashion (is it "in accordance with established procedure").

D. Applicability Determinations and Other EPA Actions Construing Routineness

In formal NSR applicability determinations, EPA has consistently interpreted the exclusion for "routine" activities narrowly. The Agency's most comprehensive discussion of the exclusion came as part of an applicability determination for WEPCO's Port Washington utility

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4. See, e.g., Alabama Power Co. v. Costle, 636 F.2d 323, 401 (D.C. Cir. 1979) (requiring EPA to allow replacement of depreciated capital goods without a PSD permit where no increase in emissions at the source would result, due to offsetting decreases, because "Congress wished to apply the permit process . . . only where industrial changes might increase pollution in an area, not where an existing plant changed its operations in ways that produced no pollution increase)."

5. See, e.g., Comments of NRDC on NSR Reform proposed rulemaking (63 Fed. Reg. 39857, Notice of Availability, July 24, 1998), EPA Docket No. A-90-37, Oct. 8, 1998.

life extension project, which was upheld by the United States Court of Appeals for the Seventh Circuit. As in the present case, EPA's analysis began with the breadth of the modification provision, turning next to "the very narrow exclusion provided in the regulations," that is, the exclusion for "routine" activity. See Memorandum from Don R. Clay, Acting Assistant Administrator for Air and Radiation, to David A. Kee, Air and Radiation Division, Region V, at 3 (Sept. 9, 1988) (Clay Memo). EPA then described the core test for meeting this exclusion: "In determining whether proposed work at an existing facility is 'routine,' EPA makes a case-by-case determination by weighing the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding." Id. Applying these commonsense factors, the Agency concluded that the WEPCO project was "far from being a regular, customary, or standard undertaking for the purpose of maintaining the plant in its present condition." Id. [6]

The WEPCO determination and subsequent court case led to significant national attention, Congressional hearings, and statutory and regulatory changes, but neither the provisions regarding routine activity nor EPA's interpretation of those provisions were affected.

Beyond the WEPCO decisions, EPA has given further guidance in other NSR and NSPS applicability determinations and related actions which elaborate on the preceding factors.[7] For example, in a 1987 applicability determination regarding the reactivation of a roaster/leach/acid plant at the Cyprus Casa Grande Corporation's copper mining and processing facilities, EPA determined that the proposed project would constitute a "major modification," and did not fall into the "narrow and limited set of exclusions" from PSD, including the exclusion for routine activity. See Letter from David P. Howekamp, Director, Air Quality Management Division, Region IX, to Robert T. Connery, Esq., at 3-4 (Nov. 6, 1987). In particular, EPA concluded that

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6. Specifically, WEPCO proposed to modify its facility in a way that would replace numerous major components of the facility (including the steam drums), would require pre-approval from the state utility commission, would significantly enhance the efficiency and current production capacity of the plant and extend its useful life, would rarely be repeated during a unit's life, and would cost a substantial amount of money, over half of which was designated as capital costs. Id. at 4-6. On review, the Seventh Circuit upheld this portion of EPA's determination in its entirety. See WEPCO, 893 F.2d at 910-13.

7. In addition to the guidance discussed above, EPA's narrow interpretation of the exclusion for routine activity is evident from a passage in its brief to the Seventh Circuit in WEPCO. That brief generally reiterates the points addressed in the applicability determination that was the subject of the litigation, but elaborates with a helpful example. EPA analogized industrial facilities to automobiles, emphasizing that the "regulatory exception for routine, maintenance, repair and replacement was meant to cover such things as an oil change, replacing a broken headlamp or worn-out tires, changing the sparkplugs, or other similar activities," rather than permitting the replacement of such items as the engine or transmission. Respondent's Brief at 51, WEPCO v. Reilly, 893 F.2d 901 (7th Cir. 1990) (Nos. 88-3264 & 89-1339).

because the project called for the replacement of integral components and would entail significant time (4 months) and cost (an absolute cost of $905,000, which constituted 10 percent of the cost of replacing the repaired unit), it was not routine. Id. at 5-6. The agency also noted that certain activities, although they would be routine "if performed regularly as part of standard maintenance procedure while the plant was functioning or in full working order," were being performed as part of an extensive rehabilitation project and, thus, were properly considered non-routine. Id. at 6; see also In re: Monroe Electric Generating Plant, Petition No. 6-99-2 at 11, 19 & n. 19 (Adm'r 1999) (in grant of CAA § 505(b)(2) veto petition, stating principle that a non-routine collection of activities, considered 'as a whole,' is not exempt under routine exclusion, even if individual activities could be characterized as routine). In another case, in 1975, EPA Region X determined that the upgrade of boilers at a pulp mill was non-routine under NSPS, in that it called for the addition of additional pressure parts previously not included in the boilers to increase the superheater surface of the boilers, even though the additional parts were contemplated under the original boiler design. Request for Ruling Regarding Modification of Weyerhaeuser's Springfield Operations, Reg. Counsel, Reg. X (Aug. 18, 1975). When reviewing whether a project was routine, other applicability determinations have considered whether the project involved: (1) the addition of certain parts previously not included in the units; (2) the expansion of parts of a unit; or (3) the replacement of an entire emissions unit. For copies of these actions and other applicability determinations and guidance documents, please see EPA's publicly-available databases, available at: http://www.epa.gov/ttn; http://www.epa.gov/region07/programs/artd/air/nsr/nsrpg.htm; and http://www.epa.gov/oeca/eptdd/adi.html, or contact the staff members named in the cover letter.

In sum, in these actions and elsewhere, EPA has assessed routineness by considering the following factors:

Nature

- Whether major components of a facility are being modified or replaced; specifically, whether the units are of considerable size, function, or importance to the operation of the facility, considering the type of industry involved
- Whether the change requires pre-approval of a state commission, in the case of utilities
- Whether the source itself has characterized the change as non-routine in any of its own documents
- Whether the change could be performed during full functioning of the facility or while it was in full working order
- Whether the materials, equipment and resources necessary to carry out the planned activity are already on site

Extent

- Whether an entire emissions unit will be replaced
- Whether the change will take a significant time to perform
- Whether the collection of activities, taken as a whole, constitutes a non-routine effort, notwithstanding that individual elements could be routine

- Whether the change requires the addition of parts to existing equipment

Purpose

- Whether the purpose of the effort is to extend the useful life of the unit; similarly, whether the source proposes to replace a unit at the end of its useful life
- Whether the modification will keep the unit operating in its present condition, or whether it will allow enhanced operation (e.g., will it permit increased capacity, operating rate, utilization, or fuel adaptability)

Frequency

- Whether the change is performed frequently in a typical unit's life

Cost

- Whether the change will be costly, both in absolute terms and relative to the cost of replacing the unit
- Whether a significant amount of the cost of the change is included in the source's capital expenses, or whether the change can be paid for out of the operating budget (i.e., whether the costs are reasonably reflective of the costs originally projected during the source's or unit's design phase as necessary to maintain the day-to-day operation of the source)

These categories are interrelated. Many facts could be relevant to both nature and extent, while others could overlap with purpose. Moreover, none of these factors -- standing alone -- conclusively determines a project to be routine or not. *Instead, a permitting authority should take* account of how each of these factors might apply in a particular circumstance to arrive at a conclusion considering the project as a whole.

3. Analysis of Detroit Edison's Objections to EPA's Longstanding, Narrow Interpretation of the Exclusion for Routine Activity

In support of its request, Detroit Edison has submitted a number of documents in which members of the electric utility industry claim that EPA has recently changed its interpretation of the routineness exclusion by narrowing it and that EPA's prior interpretation was expansive. See, e.g., Supplemental Comments of the Utility Air Regulatory Group, EPA Air Docket No. A-90-37 (Oct. 8, 1999) (UARG Comments).[8] As discussed below these arguments lack merit. Moreover, it bears noting that if companies have specific questions about the scope of the exclusion, EPA has long encouraged sources to seek guidance from their permitting authorities, see New Source Review Workshop Manual at A.33-34 (Draft Oct. 1990).

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8. The UARG comments submitted by Detroit Edison in support of its applicability determination request pertain to the ongoing "NSR Reform" rulemaking. See 61 Fed. Reg. 38250 (1996). The views expressed here regarding the UARG Comments pertain only to this applicability determination and are without prejudice to the ultimate outcome of the pending rulemaking.

a. Claim that Construction that Does Not Increase Unit's Emission Rate Is Routine

Among Detroit Edison's contentions is the assertion that the routine activity exclusion is properly read (and historically has been read by EPA) to cover all "capital projects to replace degraded components without increasing the design capacity or maximum achievable hourly emission rates." See UARG Comments at 43. This interpretation would leave NSR to cover only "those activities that would create 'new air pollution' by significantly increasing the pollutant emitting capabilities of the source as designed and built." Id. at 13. In essence, this argument holds that extensive construction activity at a source is exempt from new source requirements, even if actual emissions to the atmosphere increase, where the source's potential to emit does not increase. This contention does not withstand scrutiny. EPA's regulations have since 1980 explicitly required keying NSR applicability for modifications to the actual emissions consequences of a particular change. See, e.g., 40 C.F.R. §§ 52.21(b)(2)(i) (defining "major modification" as a change resulting in a significant "net emissions increase"); 52.21(b)(3)(i) (defining "net emissions increase" based on "actual emissions"); see also 45 Fed. Reg. 52676, 52700 (Aug. 7, 1980) (explaining EPA's adoption of actual emissions baseline for modifications). Industry has understood this facet of the NSR program from the outset; indeed, it was one of the central points on which industry sought review of the 1980 regulations. See Brief for Industry Petitioners on Actual Emissions Definition of Net Increase, Chemical Mfrs. Ass'n v. EPA (D.C. Cir.) (No. 79-1112). Accepting Detroit Edison's proffered interpretation of the routine activity exemption, however, would moot this longstanding and contentious quarrel and would make meaningless the provisions in the regulations governing the actual emissions baseline for modifications. This runs counter to the general presumption that interpretations that render part of a regulation superfluous are to be avoided. See, e.g., U.S. v. Larson, 110 F.3d 620, 626 (8th Cir. 1997); accord WEPCO, 893 F.2d at 909 (rejecting WEPCO's proffered definition of "physical change," because it "would open vistas of indefinite immunity from the provisions of NSPS and PSD").[9]

b. Mary Nichols Representation that "Restoration" Activity Can Be Routine

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9. The argument that only changes that increase a unit's emissions rate can trigger the NSR modification provisions has been rejected by two courts of appeals. As noted, see supra note 1, in Puerto Rican Cement, the First Circuit rejected a claim that modifications to a cement kiln, which made production more efficient and decreased the hourly emissions rate but could increase the plant's utilization rate, such that actual emissions to the atmosphere might increase, were exempt from PSD. The company argued that the project fell under the PSD regulatory exclusion for changes that result in an "increase in the hours of operation or in the production rate." See 889 F.2d at 298. Similarly, in WEPCO, where the company was making "like-kind" replacements of components to restore the original design capacity of the plant, there was no increase in emissions per unit of output; rather, for PSD purposes, the emissions increase was attributable to increased utilization. The Seventh Circuit rejected the company's reliance on the exclusion for increased hours of operation/rates of production. See 893 F.2d at 916 n. 11.

In the submitted materials, utility representatives claim that EPA has previously indicated that the utilities may undertake facility restorations without considering NSR. In 1995, industry encouraged EPA to propose to amend the NSR rules to include a "restoration" exclusion for any change that enabled a deteriorated unit to increase its emissions, as long as the unit did not exceed its highest recent (i.e., in the last 5 years) achievable capacity. EPA responded by saying that it intended to propose a number of flexible mechanisms to allow sources to make changes without triggering NSR. The Agency also said, "EPA believes that the routine maintenance exclusion already included in the existing NSR regulations also has the effect of excluding 'routine restorations.'" Letter from Mary D. Nichols, Assistant Administrator for Air and Radiation, to William R. Lewis, Morgan, Lewis and Bockius, attachment at 19 (May 31, 1995). Some in industry quarters suggest that this sentence indicates EPA's interpretation that restoration activities are, by definition, exempt. See UARG Comments at 17 ("In 1995, [EPA] confirmed that no special rule was needed for industrial 'restoration' projects because such projects were covered already under the 'routine maintenance' exclusion."). These claims are incorrect. Rather, EPA's statement says merely that "routine restorations," not all "restorations," are exempt. Thus, EPA's remark simply is tautological; it says that to the extent the restoration is itself "routine," the current exclusion for "routine" activity will exempt it from review.[10]

c. Assertion that EPA Expects No Change to Trigger NSPS Modification Provision

Detroit Edison also maintains that several EPA documents indicate that the Agency believed until recently that utility modifications would generally avoid NSR, and that these documents therefore reveal an expansive understanding of the exemption for routine activity. In particular, the UARG Comments highlight a General Accounting Office (GAO) report created when Congress was considering the acid rain program,[11] a letter to Senator Byrd from EPA regarding a proposed NSPS, and the preamble to the proposed NSPS.[12] Although none of these documents discuss the scope of the routine maintenance, repair, and replacement exemption,

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10. For example, past piecemeal repairs and replacement of individual rotor blades at Monroe presumably restored some portion of the efficiency lost since the last scheduled outage. While not the subject of this determination, it appears that those activities – which as explained above were far different from the proposed Dense Pack upgrade – are more likely to be properly characterized as excluded "routine restorations."

11. UNITED STATES GENERAL ACCOUNTING OFFICE, PUB. NO. GAO/RCED-90-200, ELECTRICITY SUPPLY: OLDER PLANTS' IMPACT ON RELIABILITY AND AIR QUALITY (1990).

12. The submissions also refer to an article written by EPA staff. This document warrants no discussion; it does not represent Agency opinion, as noted in the cited article. See James DeMocker et. al, Extended Lifetimes for Coal-fired Power Plants: Effect Upon Air Quality, PUBLIC UTILITIES FORTNIGHTLY at 30 n.* (Mar. 20, 1986). Moreover, the article is silent on the question at issue here -- when certain activity is routine -- and therefore would not be relevant even if it did speak for EPA.

industry points to them as evidence that EPA believed that NSR would apply to electric utilities only rarely.

The cited documents do not remotely suggest a broad EPA interpretation of the routineness exemption. First, although the GAO report contains a number of statements that suggest that EPA did not expect many utilities to trigger the NSPS or PSD modification rules, it does not suggest how broadly or narrowly the exclusion for routine activity has been interpreted; further, some statements in the report are best read as reflecting a narrow scope to the exclusion. GAO Report at 28, 30 (acknowledging that "life extension projects involve physical or operational changes to power plants" and distinguishing between projects aimed at restoring generating capacity and those which prevent plant deterioration). In addition, as noted above, the PSD regulations provide broad leeway for sources to avoid new source requirements by making offsetting emissions reductions at the source even when undertaking extensive physical or operational changes that, standing alone, would result in emissions increases. In many circumstances, such "netting out" of review is a more cost-effective strategy than obtaining a PSD permit. Moreover, at the time of the 1990 CAA Amendments, any statement or assumption EPA made regarding whether electric utilities could trigger NSR was based on information provided by industry at that time. The power plant undertaking a physical or operational change is responsible for obtaining the necessary regulatory approvals from each agency that regulates it. State and federal environmental agencies do not regularly review submissions to public utility commissions, the Federal Energy Regulatory Commission, a pipeline authority or a local zoning board; nor are those agencies charged with the authority to require CAA permits. As a result, EPA, as well as states, were unaware that activities that were under way at utilities would in fact increase emissions and thus trigger NSR. Although EPA's conclusions were reasonable based on the information EPA had at the time, EPA's statements might have been different based on more complete information, including information from facilities requesting applicability determinations.

Second, the utilities point to a letter to Senator Byrd from OAQPS Director John Seitz regarding potential revisions to the NSPS for steam generating units and to the preamble to a 1997 proposed rule on the same topic. Both documents indicate that EPA expected few, if any, existing units to become subject to the proposed NSPS as a result of being modified. Again, these documents do not suggest that the reason EPA had such an expectation was because of a broad interpretation of the exemption for routine activity. Indeed, the preamble to which industry refers has a lengthy discussion of the reasons why existing units would avoid the NSPS for modifications, but notably omits the "routine" exclusion. See 62 Fed. Reg. 36947, 36957 (July 9, 1997).[13]

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13. In addition, the UARG Comments claim that a "key" factor in the D.C. Circuit's recent vacatur of the fossil-fuel boiler NSPS for modified units was that some EPA offices viewed quite a bit of "maintenance" activity as potentially covered by the modification provision and others thought that few, if any, changes would trigger the NSPS. UARG Comments at 3 n.8.
(continued...)

d. Assertion that Industry Practice Defines Routineness

The submitted materials also seem to contend that if a particular industry sector has an established practice of undertaking certain construction activity, no matter how infrequent, costly, or major, that industry practice is "routine." See UARG Comments at 37 ("[E]lectric utilities undertake maintenance, repair and replacement activities pursuant to their legal obligation to provide a safe and reliable source of electricity. This defines what is 'routine' for this industry.") It is true that EPA has stated that the "determination of whether the repair or replacement of a particular item of equipment is 'routine' under the NSR regulations, while made on a case-by-case basis, must be based on the evaluation of whether that type of equipment has been repaired or replaced by sources within the relevant industrial category." 57 Fed. Reg. at 32326. However, this statement merely recognizes that a piece of equipment may be more integral, costly, or less frequently replaced at one kind of facility than at another. Accordingly, although it may not be routine for one industry to replace or repair certain equipment or undertake certain maintenance activity, similar construction might be routine in a different industry. As a result, EPA has historically considered whether a typical source in the relevant industry undertakes the proposed activity as a routine matter. See, e.g., 40 C.F.R. §60.14(e)(1) (NSPS regulations require EPA determination that activity is "routine for a source category" to be exempt). This does not mean, however, that whatever activity members of a particular industry have done – no matter how infrequent, costly, sizable, or capable of expanding the source's operations or extending its useful life – is necessarily routine.

B. Analysis of "Routine" Maintenance, Repair or Replacement at the Monroe Plant

Looking at the nature, extent, purpose, frequency and cost of the project, along with other relevant factors in light of the framework discussed above, EPA concludes that the proposed Dense Pack project is a non-routine physical change. In sum, although utilities typically perform maintenance, repair and replacement of individual deteriorated turbine blades about once every four years, the reconfiguration and upgrade of a turbine's entire high-pressure section (including all of the blades) is a significant departure from necessary maintenance operations aimed at keeping the turbine in ordinary working condition, and is rarely performed at a typical utility. Detroit Edison expects the new Dense Pack configuration to substantially increase the unit's ability to convert steam to electricity over its original design and the project will reduce the rate of blade efficiency deterioration by 70%. Moreover, the new blades will alter the inspection and replacement program of worn blades, allowing inspection and replacement to occur every 10

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13. (...continued)
Research has revealed no support for this assertion. The court's order in the case is brief and does not suggest a reason for its disposition of the matter, except that the court believed that the NSPS for modified boilers was "seriously deficient." Lignite Energy Council v. EPA, No. *98-1525 (D.C. Cir. Sept. 21, 1999).*

years instead of 4 years. Finally, the project requires a significant capital expenditure of $12 million, which Detroit Edison states is triple the cost of replacing the worn blades with ones of the same design, and which vastly exceeds prior blade and rotor maintenance costs. A more detailed application of the relevant factors to the information that Detroit Edison has submitted regarding the Dense Pack project follows.

Nature and Extent

Detroit Edison seeks to replace the entire high-pressure section of two turbines to allow for use of a new type of turbine blade and to reconfigure the design to improve efficiency. This includes reconfiguration of blades in the high-pressure sections of the two units, including new parts and additional stages. The turbine – in particular the high-pressure section – is an integral and major component of an electric generating facility. Furthermore, the proposed change will be of considerable importance to the operation of the facility because, among other options, it will enable the units to produce more electricity with the same coal usage, boiler heat input and steam flow, and allows operation of the units with less maintenance. In addition, by making operation of the affected units more efficient, the Dense Pack upgrade will provide an economic incentive to increase operations at the plant.

Several other facts that EPA has found telling in past decisions and guidance also indicate that the Dense Pack upgrade would not be routine. First, the project cannot be performed during the full functioning of the plant and instead would require the affected units to be shut down. Second, the project would involve the addition of parts not previously used. Third, the project could not be completed with parts typically stored on site. Finally, Detroit Edison plans to capitalize 100% of the cost of the project.

Purpose

Replacement of currently deteriorated blades with blades of the same design would restore only 2% of the efficiency that has been lost as the equipment has aged, leaving the units 5% below their original efficiency rating. The Dense Pack project, however, would increase efficiency of the high-pressure sections of the turbines over current levels by 12%, and overall efficiency of the turbines by 4.5%. The new configuration could reduce efficiency deterioration by 70%.

Thus, the Dense Pack project will not simply maintain the equipment at the current state, but will enhance the operation of the Monroe Power plant by recovering the accumulated lost efficiency, increasing the efficiency over the original design, and decreasing the rate of turbine blade deterioration in the high pressure section. This efficiency enhancement and decrease in deterioration rate would in turn substantially enhance the operational capabilities of the affected units, by providing an economic basis for increased utilization. As discussed below, Detroit Edison claims that it does not intend to use the unit more in the future as a result of the Dense Pack project, but that does not change the fact that the project would enable it to do so.

Frequency

Turbine upgrades like the Dense Pack project are performed rarely, if ever, in the course of a utility source's life. Detroit Edison has not provided any information to suggest that individual facilities in the industry frequently conduct a complete replacement of the high pressure section of a utility steam turbine, relying instead on two claims: (1) that utilities commonly perform turbine maintenance activity; and (2) that it estimates that projects "similar" to the Dense Pack have been performed at a number of utilities. Neither of these claims addresses the central question - whether it is industry practice that a typical facility will frequently conduct the project in question. The only available information -- Detroit Edison's experience – suggests that projects like the Dense Pack are performed infrequently at individual sources; this project has never been performed previously at Monroe and will greatly increase the time between "overhauls" of the high pressure section.

Cost

Detroit Edison expects the Dense Pack project to cost approximately $12 million. Detroit Edison has estimated that replacement of the current blades with blades of the same design would cost approximately $2 million per unit. Generally speaking, a new plant costs approximately $2,000 per kilowatt. Therefore, a new 750 megawatt unit would cost about $1.5 billion.

An absolute cost of $12 million constitutes a significant cost, which tends to make this project non-routine. Detroit Edison argues that the cost of the Dense Pack project is significantly less than the cost of the Port Washington project at issue in the WEPCO case. In WEPCO, the estimated cost of the life extension project was $87.5 million, at least $45.6 million of which was capital costs. Clay Memo at 6. EPA acknowledges that this cost is well in excess of the proposed Dense Pack project, especially considering inflation. However, as the Agency noted in 1988, WEPCO's activity was "far from" routine, id. at 3, and the facts of that case should be considered in that context. By contrast, EPA has determined that a proposed project costing $905,000 was non-routine. Letter from Howekamp to Connery at 5. Considering these two precedents, EPA believes that the $12 million expenditure in this case, all of which is capital in nature, supports a determination that the proposed project is non-routine.

Although the relative cost of the Dense Pack project, when compared with replacing the entire electric generating facility, is small, it is orders of magnitude larger than other blade maintenance activity Detroit Edison has conducted in the past. For instance, it appears that the company spent $18,700, $33,100, and $7,900 to replace high-pressure rotors in three projects in 1981 and 1982. Further, the project is significantly more costly than simply replacing deteriorated blades today; Detroit Edison acknowledges that the Dense Pack upgrade would cost three times more than its alternative blade repair and replacement project.

V. Emissions Increase

Since the Dense Pack project constitutes a physical change, EPA must consider whether it would result in a significant net emissions increase. Before providing its analysis, once again EPA will review what the regulations require. Thus, the following discussion provides a context for the analysis of the project that follows.

A. Regulatory Requirements

If a physical change or change in the method of operation is not "routine," it still does not trigger PSD unless it results in a significant net emissions increase. This involves comparing recent pre-change, or "baseline", actual emissions to a projection of future actual emissions following the change. A source's pre-change level of actual emissions from a given unit is "the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the [date of the change] and which is representative of normal source operation." Id. § 52.21(b)(21)(ii). This figure must be compared to the source's post-change emissions; however, because NSR is a preconstruction program, one must project the unit's future emissions. For units that are not "electric utility steam generating units," EPA's rules require that for units that have "not begun normal operations," i.e., units that will undertake a non-excluded physical or operational change, the post-change emissions "shall equal the potential to emit of the unit," which is the "maximum capacity of a stationary source to emit a pollutant under its physical and operational design," but which also accounts for pollution controls and permit restrictions that limit lawful emissions to a level below the maximum physical capacity. Id. § 52.21(b)(4).[14] If a particular change would, standing alone, increase actual emissions by more than a "significant" amount, see id. § 52.21(b)(23), the change is subject to PSD, unless other activity at the source renders the net emissions effect of the change insignificant when considered together with contemporaneous (generally within the past five years) emissions increases and decreases at the source. See id. § 52.21(b)(3) (defining "net emissions increase").

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14. Under current regulations, changes to a unit that are not routine nor subject to one of the other NSR exemptions are considered to be of such significance that pre-change emissions should not be relied on in projecting post-change emissions. For such units, "normal operations"refers to operations after the change, and are deemed not to have begun. The regulations initially presume that such units will operate year-round at full capacity, but a source owner is free to overcome the presumption by agreeing to limit its potential to emit to any level desired through enforceable restrictions on operations or the use of pollution controls. For example, if limiting the potential to emit results in an insignificant change in emissions, the source can avoid PSD applicability. See 63 Fed. Reg. 39858 (July 24, 1998) (Notice of Availability); see also 45 Fed. Reg. 52676, 52688-89. If business plans later change and the owner desires to relax those restrictions and obtain a PSD permit at that later time, it may do so. See 45 FR 52689; 54 FR 27274, 27280.

For electric utility steam generating units, the post-change emission increase calculation is governed by regulations adopted in 1992 (57 Fed. Reg. 32314, July 21, 1992), commonly referred to as the "WEPCO rule." Although the WEPCO rule did not change the regulatory provision that establishes a unit's pre-change emissions, EPA announced that it would view any consecutive two-year period during the preceding five years as presumptively reflective of "normal source operations." See 57 Fed. Reg. at 32324-25. In addition, EPA amended the regulations regarding a utility unit's post-change emissions in two ways. First, the rules allow utilities to project future emissions resulting from a particular change without committing to a permit restriction limiting the unit's potential to emit to a level below its maximum capacity to emit a pollutant,[15] and they provide that emissions increases independent of the physical or operational change may be discounted from the post-change emissions of the unit. A utility making a particular change, instead of accepting permit restrictions on the potential of the changed unit to emit a particular pollutant, may avoid PSD if its projection of "representative actual annual emissions" following the change is not significantly greater than its pre-change emissions, but only if the source "maintains and submits to the Administrator [or relevant state permitting authority] on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase." E.g., 40 C.F.R. § 52.21(b)(21)(v). Second, in evaluating the source's claimed exemption from PSD, the permitting authority must "[c]onsider all relevant information, including, but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act. . . ." Id. § 52.21(b)(33)(i). The permitting authority must discount any increase "that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole." Id. § 52.21(b)(33)(ii). Nevertheless, if an emissions increase could not have occurred "but for the physical or operational change," the increase must be considered to result from the change. See 57 Fed. Reg. at 32327.

Where the end result of an emissions increase analysis for electric utilities is a projection

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15. We are aware, as Detroit Edison states in its initial applicability determination request, that EPA Region VII previously has suggested that a utility undertaking a change to a part of the source other than the boiler may not be entitled to take advantage of the provision that allows for a forecast of future emissions without committing to a present limitation on the source's potential to emit. We have reviewed Region VII's discussion of the matter and the applicable regulations, and we conclude that Detroit Edison may use this provision to calculate future emissions from the boilers, even though it is making changes at the turbines. The plain language of the regulation is categorical; irrespective of where a change takes place, the post-change emissions of the electric utility steam generating unit – which certainly includes the boiler – must be determined using the "representative actual annual emissions" approach. See 40 C.F.R. § 52.21(b)(21)(v).

accepted by the permitting authority that emissions would not increase as a consequence of a particular change, the rules call for an initial determination that the change would not be a major modification subject to PSD. See Letter from David P. Howekamp, Air Division, Reg. 1X, to Richard K. McQuain, HEI Power Corp., at 1-2 (undated) (describing WEPCO rule as conferring conditional exemption from PSD where projected emissions increase is insignificant). However, if the information that the source must submit for the requisite number of years following the change demonstrates that emissions have in fact increased as a result of the change, the source becomes subject to PSD at that time. See 40 C.F.R. § 52.21(b)(21)(v); 57 Fed. Reg. at 32325 ("If . . . the reviewing authority determines that the source's emissions have in fact increased significantly over baseline levels as a result of the change, the source would become subject to PSD requirements at that time.")

B. Analysis of Significant Net Emissions Increase at the Monroe Plant

Because the Dense Pack project would be a physical change to a major stationary source, Detroit Edison must estimate whether the change would result in a significant net emissions increase to determine whether it must undergo PSD review. 40 C.F.R. § 52.21(b)(2)(i). According to the submission, Detroit Edison asserts that emissions will not increase as a result of the project. As discussed below, EPA accepts for purposes of this determination Detroit Edison's representation that emissions will not increase as a result of the project, and concludes that the Dense Pack upgrade will not trigger PSD, provided that, prior to beginning construction, the company validates its representation by developing and submitting to the permitting agency a calculation of "baseline" actual emissions and a projection of future actual emissions following the project.

Detroit Edison maintains that emissions will not increase as a result of this project because it concludes that one of two consequences will follow the upgrade. First, Detroit Edison claims that because the change would increase efficiency, it would allow increased electricity generation using the same amount of coal, boiler heat input and steam flow while producing the same level of emissions as currently emitted. Alternatively, Detroit Edison claims the project would enable it to generate the same amount of electricity it currently generates using less coal, boiler heat input and steam flow, resulting in reduced emissions. Detroit Edison rejects the third possibility -- that it would use the units more, and increase emissions at the plant, as a result of the blade replacement. Detroit Edison states that these units already are at the top of the loading order and had a capacity factor of approximately 85% for 1998. Thus, the company asserts, any increase in use would be the result of demand or unforeseen outages, which could and would have occurred regardless of whether or not Detroit Edison proceeds with the Dense Pack project. The company has not, however, provided any specific projections of future operations and emissions to EPA to support its claims regarding emissions levels.

EPA disagrees that the dispatch position of the Monroe plant necessarily means that the Dense Pack project would not result in increased use, and hence, increased emissions. Given the information provided by the company showing that there is some fluctuation in annual use and

that Units 1 and 4 are not operated at their maximum physical capacity, the fact that Monroe is at the top of the loading order is insufficient to demonstrate that the significant increase in efficiency associated with the Dense Pack project, and the corresponding decrease in the cost of producing electricity, would not result in increased use and emissions. The possibility that Detroit Edison would take advantage of Monroe's increased efficiency to sell additional power in deregulated utility markets beyond its regular service area is an additional reason that the Dense Pack project may well lead to increased emissions. Accordingly, based on the information provided, EPA cannot agree at this time that any future increased emissions at the Monroe plant due to increased use should be attributed to demand growth (as that term is used in the PSD regulations) or other factors not causally related to the Dense Pack project.

EPA notes in this regard that the large size of the Monroe units means that only a small increase in use could result in emissions increases that are significant for PSD purposes. For example, if Detroit Edison decides to run the Monroe plant even 1% more due to the improved efficiency, the resulting increase in emissions would be well above the significance threshold. If a one to five percent increase in operation were to result from the Dense Pack project, increases on the order of 160-800 tons of NOx and 400-2000 tons of SO2 would occur, each of which would be considered "significant," and trigger PSD absent sufficient offsetting contemporaneous emission reductions. See 40 C.F.R. § 52.21(b)(23)(i) (defining 40 tons per year emission increases for sulfur dioxide and nitrogen oxides as "significant").

In determining whether a nonexempt physical or operational change at an electric utility steam generating unit will result in a significant net emissions increase, the applicable PSD regulations at 40 C.F.R. § 52.21(b)(21)(v) and (b)(33) call for a calculation of pre-change "baseline" actual emissions and a projection of future actual emissions for the two year period after the change (or another two year period that is more representative of normal post-change operations). Detroit Edison has not supplied such a projection, perhaps in reliance on its position that the Dense Pack project would be exempted as routine. The company has represented, however, that "the Dense Pack would not result in an increase in the number of hours these units are expected to be operated." EPA has no specific information disputing that assertion, and so is willing to accept Detroit Edison's representation. Nevertheless, until the company provides the calculation and projection called for by the regulations to verify its projection of no increase in actual emissions, our determination is provisional. Detroit Edison should submit these figures to the Michigan Department of Environmental Quality prior to the beginning of construction.

The PSD regulations also require Detroit Edison to maintain and submit to the delegated permitting agency, for a period of 5 years from the date the units resume regular operation following completion of the Dense Pack project, information demonstrating that the project did not result in an emissions increase. To adequately track post-change emissions, EPA expects that this information must include records on annual fuel use, hours of operation, and fuel sulfur content. In making these calculations, Detroit Edison may exclude emissions increases that are caused by other factors, for example, emissions increases that it demonstrates are due to variability in control technology performance or coal characteristics. In addition, when

calculating emission increases, under current regulations Detroit Edison may exclude that portion of its emissions attributable to increased use at the unit due to the growth in electrical demand for the utility system as a whole since the baseline period. See 40 C.F.R. § 52.21(b)(33)(ii).

Finally, EPA notes that regardless of whether PSD review is triggered due to the Dense Pack project, Detroit Edison remains responsible for compliance with all other applicable federal, state, and local air pollution regulations.

VI. Conclusion

For the reasons delineated above, EPA concludes that the changes proposed by Detroit Edison would not be routine. Detroit Edison's submissions do not demonstrate that projects such as the Dense Pack are frequent, inexpensive, or done for the purpose of maintaining the facility in its present condition. Therefore, the Agency determines that the Dense Pack upgrade would be a "physical change," as that term is used in the NSR regulations. EPA disagrees with Detroit Edison's claims that the Dense Pack project is eligible for the exclusion from PSD permitting for routine maintenance, repair, and replacement. The determination of whether a proposed physical change is "routine" is a case-specific determination which takes into consideration the nature, extent, purpose, frequency, cost of the work, as well as other relevant factors. After carefully reviewing all the available information, in light of the relevant factors, EPA has determined that the proposed project would not be "routine."

The PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a nonroutine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change. Detroit Edison contends that representative actual annual emissions following the Dense Pack project will not be greater than its pre-change actual emissions, because the project will not result in increased use of the units. Therefore, Detroit Edison may avoid major PSD permitting to the extent it documents its pre-change baseline emissions and submits information following the change to confirm its pre-change projection. If Detroit Edison fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased as a consequence of the change, it will be required to obtain a PSD permit for the Dense Pack project.

Exhibit 5

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	)	
	)	
	)	
Plaintiff,	)	Civil Action No.
	)	
v.	)	
	)	
DTE ENERGY COMPANY, and	)	
DETROIT EDISON COMPANY	)	
	)	
	)	
Defendants.	)	
	)	

DECLARATION OF
ROBERT KOPPE

I, Robert H. Koppe, declare as follows:

(1) I have been asked to evaluate what effect the Monroe Unit 2 (Monroe 2) boiler upgrades would have on the amount of power that the unit will generate in the future. For the reasons described below, I concluded that the Company should have expected that the availability of Monroe 2 to generate power would be greater after the 2010 planned outage than it had been before. I also concluded that the Company should have expected that a substantial amount of the increase in availability would be due to the three boiler tube replacements. I further concluded that the Company expected that the utilization of the unit would be greater in the future than it had been in the past. The combination of increased availability and increased utilization should result in a large increase in the amount the unit generates per year. A considerable amount of the increase in generation will be due to the increased demand on the unit, that is, it will be due to increased utilization of the unit. Another considerable amount of the increase in generation will be due to the increase in unit availability that was due to the boiler upgrades. It may be that generation would have increased had the tube replacements not been implemented. However, the forecast increase in generation would have been much less but for the replacements.

MY EXPERIENCE

(2) The following is a brief summary of my background and experience. More detailed information can be found in my resume, which is in Appendix A. The documents I considered in my analysis are cited in the text and footnotes. My company is being compensated at the rate of $100 per hour for my work on this matter.

(3) I received a BS in Wood Products Engineering from the SUNY College of Forestry and an MS in Nuclear Engineering from the Ohio State University. I completed all the course work toward a Ph.D. in Nuclear Engineering at MIT, but did not complete the degree. From 1968 to 1974, I worked for the Consolidated Edison Company of New York, first as a nuclear engineer and then as manager of the nuclear engineering division. From 1974 to the present, I have been a consultant, working on nuclear and coal-fired electric generating units. Work I have done that is relevant to my work on this case includes:

- Development of industry databases on power plant performance, including the NERC GADS database, which is described later in this declaration, and which I used in developing my conclusions in this case;
- Several studies of the utility industry and other industries with respect to collection of experience data and use of that data for decision making;
- Many analyses of industry-wide experience with generating unit operations;
- Reviews and audits of design and/or operations of numerous individual generating units; and
- Calculation of the anticipated amount of future electricity generation for many individual generating units. Several of these calculations involved the changes in generation expected to result from specific changes in the design and/or operation of the unit.

THE EFFECT OF THE THREE BOILER TUBE REPLACEMENTS ON THE AVAILABILITY OF MONROE 2

INTRODUCTION

(4) Starting on March 13, 2010, Detroit Edison shut down Monroe 2 for a long planned outage. This outage lasted for more than twelve weeks.[1] The unit typically has a long planned outage once each four years.[2] There are some shorter planned outages.[3] The 2010

[1] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 2.
[2] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 4.
[3] Data the Company reported to NERC GADS.

planned outage was longer than most long planned outages at the unit. This was because both the economizer and the pendant reheater were replaced in 2010.[4]

(5) During the 2010 planned outage, the Company made a number of major improvements to the unit. The three improvements that I was asked to look at each involved replacement of a major component of the unit's boiler. Specifically, these three replacements involved:

- Complete replacement of the entire economizer;
- Complete replacement of both banks of the pendant reheater (also known as the high temperature reheater); and
- Replacement of a substantial amount of tubing in the furnace waterwall component of the boiler.[5]

(6) For each of these three replacements, the new tubes contained design features that were a significant improvement relative to the original design.[6]

(7) During the outage, the Company also made a number of other significant improvements to the unit. These included:

- Replacement of the generator exciter with a modern design;
- Replacement of the generator lead box; and
- Re-winding the generator rotor.[7]

(8) Based on my experience and the experience of the industry, I concluded that the Company should have expected that the availability of Monroe 2 to generate power would be greater after the 2010 planned outage than it had been before. I also concluded that the Company should have expected that a substantial amount of the increase in availability would be due to the three boiler tube replacements. Specifically, the Company should have expected that, but for the three replacements, the increase in the unit's availability would have been substantially smaller.

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[4] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 4. (The data the Company reported to NERC GADS show that the last major planned outage at the unit was early in 2005, which is five years before the 2010 outage, not four. Also, the 2005 planned outage was almost as long as the 2010 outage. I presume that the Company's statements reflect a longer-term view.

[5] EPA inspection Documents, page 2 "Capital Project Status"

[6] See subsequent sections of this declaration for details and citations.

[7] EPA inspection Documents, page 2 "Capital Project Status"

(9) My analysis follows. Further general background information on coal-fired electric generating units (coal units) and on outages and the performance of coal units is set forth in Appendix B.

METHODOLOGY FOR DETERMINING THE EXPECTED INCREASE IN EAF AS A RESULT OF THE REPLACEMENTS

(10) This section is devoted to a description of my methodology for determining the magnitude of the equivalent availability factor (EAF)[8] change that the Company should have expected to result from a boiler tube replacement. This same methodology has been used in several New Source Review enforcement cases including the *Ohio Edison* and *Cinergy* cases.

(11) For each replacement, I prepared a list of GADS events (outages and deratings) that occurred during the 60 months pre-replacement (the pre-replacement period) and were due to problems that the Company should have expected would be avoided in the future as a result of that replacement. Dr. Sahu identified a 24-month baseline period within the 60 months. He took the events I had identified that occurred during the baseline period. He calculated the increase in the amount of electricity the unit would be capable of generating (the increased EAF) that would occur if those events were precluded in the future and everything else stayed the same. Based on that increase in EAF and on the expected output factor for the unit, he calculated the amount of additional generation (and thus the amount of additional emissions) that the Company should have expected. Throughout this declaration, I refer to the methodology and my (or our) calculation of EAF losses or EAF changes, recognizing that the actual calculations of EAF changes were done by Dr. Sahu.

(12) In the following sub-sections, I discuss the:

- logic for the method;
- identification of the problems that would be eliminated by a replacement;
- identification of the GADS events that had been due to those problems;
- determination of the effect of contemporaneous activities on the unit's EAF; and
- conservatisms in the methodology.

[8] As explained further in Appendix B, EAF is a measure of how much of the time the unit was available to operate.

Logic for Our Method.

(13) The logic behind our methodology is:

- Prior to being replaced, the component had design deficiencies and/or was wearing out. These problems caused failures of the component;
- Those component failures were causing outages and/or deratings of the unit;
- Those outages and deratings were reducing the EAF of the unit;
- Replacing the component would eliminate these failures post-replacement. This would preclude some of the outages and deratings that had been occurring. This would increase the EAF of the unit: it would increase the amount of electricity the unit was available to generate;
- Around the time that the three replacements were implemented, the Company was doing other things to increase the EAF of the unit. These other increases in EAF would cancel out the deleterious effects of any degradation of other equipment in the unit that might be taking place; and
- At the time of the three replacements, the other things that the Company was doing would likely cause some increase in Monroe 2's EAF beyond the increase that was due to the replacements. We ignored these further increases and calculated only the increase directly due to the replacement alone. (This conservatism is incorporated into the methodology.)

What Problems Would Be Eliminated by a Replacement?

(14) To answer this question, I reviewed various DTE documents such as:

- the justifications that the Company prepared for the replacement;
- the Company's descriptions of other upgrades that it made to Monroe 2 before and during the 2010 planned outage;
- The Company's GADS data, which describe the causes of each of the outages that occurred during the 60 months prior to the start of the 2010 planned outage;
- Testimony given by Company witness Mr. Paul Fessler in 2009.

(15) Based on the information in these documents, I determined what equipment was replaced. I then determined how the new component(s) differed from the original(s); what problems the Company should have expected would be eliminated by the replacement; and the expected effect of the replacement on the EAF of the unit.

Which GADS Events Were Caused by Failures That Would be Eliminated by the Replacement?

(16) For each replacement, I reviewed each outage and derating at Monroe 2 during the pre-replacement period (the 60 months pre-replacement) to determine if it was due to the equipment that was replaced and if it was due to a failure mechanism that the Company expected (or should have expected) to be eliminated once the replacement was

implemented. In doing this, I utilized information from the Company's GADS data. The Company provided GADS data that listed all the events (outages and deratings) that the Company had reported for each unit.[9] (See later in this declaration for a description of GADS event data.)

(17) For each replacement, I prepared a table of GADS events for use by Dr. Sahu.[10] For the pre-replacement time period, my intention was to include only events that had all of the following characteristics:

- It was due primarily to a problem that was addressed by the replacement;
- It was due entirely to problems that would not have been expected post-replacement; and
- It occurred at a time when the unit would otherwise have been operated.

(18) To achieve this intention, I included in my tables only those pre-replacement events that met the following criteria:

- I included an event only if I was reasonably sure that the primary reason for the event was a problem that the Company should have anticipated would be eliminated once the replacement was implemented;
- I did not include an event that was due to a component that was replaced but was due to a problem that was not addressed by the replacement (e.g., failures due to exogenous factors such as operator errors or dropped objects); and
- Based on the Company's GADS data, I determined that, during the 60 months pre-replacements, the Company operated Monroe 2 whenever that unit was available to operate.[11] Based on that fact, I determined that the Company would have operated the unit during each hour it was shut down due to problems with any of the components of the boiler, had those problems not occurred.

[9] There are other kinds of events in GADS. Only outages and deratings are relevant to this discussion.
[10] In the end, I combined the listings of events for all three replacements into a single table – Table 2. There were several other outages that were probably due to problems that were resolved by the replacements that I did not include in Table 2. I did not include those outages because I did not have the information I would need in order to be reasonably certain that the outages were caused by problems that were resolved by the replacements. I listed those outages in Table 3.
[11] The Company operated the unit whenever it was not shut down for an outage. This is the same as saying that the Company never put the unit in reserve shutdown.

What Effect Should the Company Have Expected Other Components and Activities to Have on the EAF of the Unit?

(19) Contemporaneous with the three boiler tube replacements, other things were happening that might have affected the EAF of the Monroe 2. These include:

- Aging of other components at the unit;
- Other component replacements, which are not at issue in this matter;
- Detroit Edison's on-going programs to improve the availabilities of its units[12]; and
- Technological improvements that were taking place throughout the industry.

(20) A priori, the overall effect of all these contemporaneous occurrences might be to increase the EAF of the unit beyond the increase due to the three replacements at issue or it might be to decrease the EAF, canceling out some or all of the increase due to the three replacements at issue. Dr. Sahu only needed to calculate the portion of an EAF increase that was due to a replacement at issue. Therefore, we did not need to quantify any further increases due to contemporaneous occurrences. However, we did need to be sure that the overall effect of those occurrences was not likely to be negative.

(21) To determine if the overall effect of contemporaneous occurrences was likely to be negative, I considered five kinds of information:

- My experience of the kinds of replacements and improvement programs that were implemented throughout the industry during the same time period;
- The Company's descriptions of replacements and improvement programs it was implementing to improve the overall EAF of its units;
- My experience of the expectations of increases in EAFs throughout the industry;
- My analyses of the changes in EAFs that actually occurred throughout the industry; and
- The Company's own expectations with regard to increasing EAFs of its units.

(22) My analyses for each of the three replacements are described later in this declaration. Based on my analyses, I concluded that the Company should have expected that the overall effect of everything that was happening at and to each unit (other than the three replacements at issue) would have been some further increase in EAF or, at least, no decrease. This means that the Company should have expected that the EAF of Monroe 2 would increase by an amount greater than or equal to the amount attributable to the three replacements. (Nonetheless, the EAF increase calculated by Dr. Sahu for the three replacements together is only that portion of the increase that was due to those replacements alone.)

[12] These include a program to reduce the frequencies of boiler tube leaks and a program to reduce the durations of planned outages. See elsewhere in this declaration for citations concerning these programs.

Conservatisms in My Methodology.

(23) My methodology for determining the EAF increase that the Company should have expected due to a replacement is conservative: it understates the EAF increase. There are three reasons for this:

(24) The Method Does Not Take Account of EAF Decreases That Would Have Occurred without the Replacement. In deciding whether to replace a component, a utility will calculate the amount of additional EAF it expects as a result of the replacement.[13] The increase in EAF is calculated as the difference between:

- The expected future EAF if the component is replaced (usually this is more than recent experience, because the new component will be more reliable than the old); and
- The expected future EAF if the component is not replaced (usually this is less than recent experience, because the old component will continue to deteriorate).

(25) This approach, which I have found is universal in the utility industry, is illustrated in Figure 1. I was asked to calculate increased EAF in a different way. Specifically, I was asked to calculate increased EAF as the difference between:

- The expected future EAF after the component was replaced, and
- The actual historical EAF before the component was replaced.

(26) This approach is also illustrated in Figure 1. I have found that this approach almost always understates the increase in EAF due to a replacement. That is because it only accounts for the increase in EAF above the historical level. It does not account for the decrease in EAF that would have occurred without the replacement, but was avoided as a result of the replacement.

(27) Effects of Other Improvements That the Company Made in the Same Time Period as a Replacement. At the time of the three replacements, the Company was making other improvements to Monroe 2. Some of those improvements should have been expected to result in some additional increase in the unit's EAF, beyond what was expected as a result of the replacements. Had it not been for the replacements, the components would have continued to deteriorate, resulting in further decreases in the unit's EAF. These decreases would have offset (cancelled out) some or all of the increases due to the other improvements. Thus, some or all of the increases that should have been expected in unit

[13] Ultimately, utilities are interested in the additional generation attributable to a replacement. Additional generation is calculated as additional EAF times an expected utilization factor.

EAF due to the other improvements are attributable to the replacement at issue: they would not have taken place without that replacement.

(28) The analyses that Dr. Sahu and I did only take account of increases in EAF that were due to the replacements alone. They do not take account of further increases in EAF that were due to other Company activities, but would not have occurred without the replacement. Thus, our results understate the increases in EAF that were attributable to the replacements.

(29) The same reasoning I described two paragraphs back also applies to increases in output factor (OF) for the unit. OF is the power the unit actually generated divided by the power it could have generated had it always operated at its capability (full power) when it was operating.[14] The Company expects that the OF for Monroe 2 will be greater post-replacements than it was pre-replacements. Had some or all of the three replacements not been implemented, the EAF of Monroe 2 may have decreased as a result of deterioration of the components. This would have offset some or all of the increase in generation that was attributable to increased OF. Thus, some or all of that increase was attributable to the replacement: it would not have happened without the replacement.

(30) Omission of Some Historical Unavailability. Prior to implementation of the replacement, problems with the three components of the boiler were causing outages and/or deratings at Monroe 2. These events were reducing the amount of electricity the unit was available to generate: they were reducing the EAF of the unit. By eliminating these causes of EAF losses, the replacements will increase the unit's EAF, increasing the amount of electricity generated and, thereby, increasing emissions. The bigger the pre-replacement EAF losses due to the three components of the boiler, the bigger the increase in EAF (and in emissions) as a result of the replacements will be.

(31) The data in Table 2 tend to understate the pre-replacement EAF losses that were due to problems that were subsequently resolved by the replacements. This means that Dr. Sahu's calculations tend to understate the increases in EAF (and therefore the increases in generation and emissions) that the Company should have expected. There are four factors that tend to make my analyses understate pre-replacement EAF losses related to replacements. Some of these factors likely had little or no effect on some or all of my results for the replacements. Taken together, they likely caused some conservatisms in my results for some of the replacements.

[14] In prior cases, I have generally used utilization factor where I here use OF. The OF is numerically equal to the utilization factor I have used in prior cases.

(32) The four factors are:

- I only included a GADS event in Table 2 when I could be reasonably sure it was caused by a problem that was addressed by one of the three replacements. For some events, I could not find a complete description of the event cause in the GADS data. I identified several outages that were probably due to problems that were resolved by the three replacements. These are listed in Table 3. As a result, I may have omitted some events that I should have included;[15]
- It is my experience that replacement of major components often results in a decrease in the amount of work to be done during planned outages. This in turn sometimes results in shorter planned outages in the future. It may also permit the unit to run longer between planned outages in the future. It is likely that some of the replacements at issue resulted in shorter planned outages and/or permitted less frequent planned outages. The Company has said that it is working to reduce the durations of planned outages at its coal units. I did not have the kind of information I would need to determine how much the planned outage hours would be decreased as a result of the three replacements. Therefore, I assumed no change;
- The replacements together will eliminate many outages per year at Monroe 2. Startup and shutdown of the unit for these outages had been causing degradation of other components in the unit. The replacements will decrease the number of startup/shutdown cycles on the unit and this will decrease the number of outages caused by deterioration of other components. I did not take any account of this effect in my analyses; and
- When the unit is started up after an outage, its power level starts out low and is ramped up to full power over a period of several hours. At the start of some outages, the power is ramped down over a period of a few hours. During these startup and shutdown ramps, the unit is limited to less than full power. These ramps should be reported to GADS as deratings. During the 60 months pre-replacements, the Company never reported any startup or shutdown ramps. This means that the EAF losses in my Tables 2 and 3 understate the actual losses. It is my experience that for the kinds of outages listed in Tables 2 and 3, the failure to report startup and shutdown ramps causes the EAF losses due to those outages to be understated by five to ten percent.

BACKGROUND

(33) Monroe 2 entered commercial service around 1973.[16] This means that it has now been in operation for about 37 years. At the time units such as Monroe 2 were built, there was a general expectation in the industry that the units would operate for 30 to 35 years and would then be retired, or relegated to peaking service. Thus, Monroe 2 has already

[15] I reserve the right to supplement my results should more information become available.
[16] My estimate based on information in EPRI report NP-1191, dated September 1979.

operated beyond its originally expected life. It is not surprising that some components, including some components of the boiler, have worn out.

(34) A unit such as Monroe 2 will usually operate for every, or almost every, hour that it is available. In fact, during the five years (60 months) preceding the 2010 planned outage, the unit actually operated for every hour it was available.[17] Each hour the unit is shut down due to a boiler tube leak is another hour the unit would have operated, but did not. If the amount of outage time due to boiler tube failures is reduced by one hour, the unit will operate for that additional hour. (The unit operates every hour it is able (available) to operate. During that one additional hour, a large unit such as Monroe 2 will burn hundreds of tons of coal, and will emit several tons of SO_2 and NO_X. A typical large coal unit such as Monroe 2 will emit more than 40 tons of SO_2 in a day of operation. This means that increasing the availability of a large unit such as Monroe 2 by only one day per year will increase emissions by more than enough to trigger PSD.

THE THREE BOILER TUBE REPLACEMENTS

(35) In this section, I discuss each of the three boiler tube replacements that were done during the 2010 planned outage. In the following section, I discuss the expected effect of the three replacements, and other contemporaneous work, on the availability of Monroe 2.

The Economizer Tube Replacement

(36) A well-designed economizer should operate for decades, while causing only infrequent outages of the unit. When an economizer wears out, and starts causing more frequent outages, this is almost always due to coal-ash erosion. Combustion gasses (smoke) from the furnaces pass over the outside of the tubes in the economizer. If the velocity of the gasses is too high, ash from the coal, which is carried by the combustion gasses, wears away the outsides of the tubes. In some designs, ash plugs the spaces between some of the tubes. This reduces the area available for the combustion gasses to flow through the economizer, which increases the velocity of those gasses, which increases the rate of wear of the tubes.[18] Eventually the walls of the tubes become so thin in places that the pressure of the water inside the tube causes the tube to burst. When this happens, the unit must be shut down while the leak is repaired. The key to designing a good economizer is to provide enough space between the tubes so that the gas velocity is relatively low and so ash-plugging between the tubes is minimized.

[17] My analysis of data the Company reported to NERC GADS.
[18] It also reduces the efficiency of the unit.

(37) Some economizers, especially some of those that were designed in the 1960s, had high gas velocities, and wore out in as little as 10 to 20 years, or even less. Prior to the 2010 replacement, the economizer at Monroe 2 was still original equipment, which means it had been in service for about 37 years.[19]

(38) During recent years, the tubes had worn to the point where economizer tube leaks were causing outages of the unit several times per year, and the amount of outage time per year due to the economizer had been increasing with time.[20] The Company expected that the amount of outage time per year caused by the economizer would continue to increase with time. This expectation is consistent with my experience and the experience of the industry. In its justification for the economizer replacement, the Company said that:

> "The Unit 2 economizer tubes have been damaged during lengthy service in an erosive environment. Tube failures and forced outages are occurring at an increasing rate. Objective: operation of the unit without forced outages caused by economizer tube failures."[21]

(39) In addition to 37 years of wear due to being blasted by coal ash, the economizer tubes had another problem. In most economizer designs, the tubes in each horizontal row are stacked directly above the ones below. As a result, the combustion gasses can pass through vertical paths (lanes) between the columns of tubes. This arrangement helps to reduce the accumulation of ash between tubes. It also helps to protect tubes from being eroded by the coal ash. At Monroe 2, some of the tubes had bowed out into the gas lanes, causing more plugging, and exposing the tubes to more intense erosion. According to EPA's inspection notes, the Company stated that replacement of the economizer was due to

> "increased forced outages due to misaligned tubes, which affect the flue gas flow around the tubes causing unwanted velocity gradients inside the boiler, and pluggage in the backpass."[22]

(40) The Company said that it replaced the entire economizer.[23] I take this to mean that all the tubing in the economizer was replaced. I have not seen any indication that the tube headers in the economizer were replaced, and I assumed that they were not.

(41) Better economizer designs require more space between tubes. This requires that the overall volume of the economizer be relatively large. The problem that is faced when an

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[19] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 2.
[20] My analysis of data the Company reported to NERC GADS.
[21] Detroit Edison's PAT review request form for PMP project 5240, replacement of economizer at Monroe 2, revision dated 2/5/10.
[22] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 2.
[23] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 2.

economizer in an existing unit is replaced is how to reduce gas velocities and reduce plugging, while working within the relatively small space in the unit. The industry has developed designs that address this issue. Also, the industry has developed better supports for economizer tubes, which reduce the likelihood of tubes bowing into the gas lanes.

(42) I do not know what design improvements the Company incorporated in the replacement economizer. However, the Company described the replacement as being to "[d]esign an economizer which is less susceptible to erosion and which meets performance criteria set by DTE."[24] There is a lot of experience with various economizer designs, and some designs result in longer economizer lives than others.

(43) The preceding indicates that the Company expected that the replacement economizer tubes will last longer than the original ones had. Given the experience of the industry with improved economizer designs, I concluded that this was a reasonable expectation.

(44) Industry experience is that a well-designed new economizer will operate for many decades with only very occasional tube leaks. Therefore, the Company should have expected that the replacement economizer would cause very little outage time after it was installed. This would mean that there would be much less outage time per year due to the economizer after the replacement than there had been before. The Company's justification for the replacement stated that:

> "This project is to remove and replace the economizer on Unit 2 at Monroe Power Plant. With this project, the plan is to address the lost availability due to economizer tube leaks and improve reliability. The replacement will reduce future outages…"[25]

<u>The Pendant Reheater Replacement</u>

(45) The reheater at Monroe 2 consists of four banks of tubes. There are two banks of tubes that are oriented horizontally. These banks are located in the back section of the boiler. There are two banks of tubes that are oriented vertically. The tubes in these two banks hang down through the boiler roof into the top potion of the boiler. The tubes in these banks are called pendants, because they hang from above. The pendant tubes of the reheater can also be referred to as the high temperature reheater because, as described below, they operate at higher temperatures than the horizontal tubes.

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[24] Detroit Edison's PAT review request form for PMP project 5240, replacement of economizer at Monroe 2, revision dated 2/5/10.

[25] Detroit Edison's appropriation request form for PMP project 5240, replacement of the economizer at Monroe 2, dated 2/26/09.

(46) During the 2010 planned outage, the Company replaced both of the pendant banks of tubes in the reheater. The horizontal reheater was not replaced.[26]

(47) The steam coming from the high-pressure section of the turbine passes first through one and then the other of the two horizontal banks of tubes in the reheater. It then passes through one and then the other of the two pendant banks of tubes, and then goes to the intermediate-pressure section of the turbine. As a result of the preceding, the steam is hotter when it passes through the pendant components than it is when it passes through the horizontal components. In addition, the combustion gasses are hotter when they pass over the outsides of the pendant tubes than they are when they pass over the horizontal tubes.

(48) One result of the preceding is that the tube walls in the pendant reheater operate at higher temperatures than the tube walls in the horizontal components. This means that the pendant tubes are more susceptible to internal and external corrosion. Another potential problem with tubes that operate at high temperatures is a phenomenon known as creep. Creep involves a long-term degradation of the crystal structure of steel at high temperatures. After a long time, typically decades, creep can weaken the steel that makes up a tube wall, to the point that the tube bursts. This can happen even in the absence of substantial amounts of corrosion. Creep would never be an issue in the horizontal banks of reheater tubes, but could be a problem in the pendant reheater.

(49) During a recent EPA inspection, the Company stated that replacement of the pendant reheater was due to increased forced outages related to creep failure.[27] The Company stated that this was the first time that the reheater pendants had been replaced in their entirety.[28] This means that most of the tubing in the reheater had operated for about 37 years prior to being replaced.

(50) For a given operating temperature and pressure, the rate at which creep progresses can be reduced by using higher-grade steels and/or by using thicker tube walls. The use of thicker walls is usually avoided because it reduces the amount of heat that is transferred through the tube walls. The Company's justification for the reheater replacement stated that the replacement would "[u]pgrade materials to account for current and future boiler operating temperature conditions."[29] This indicates to me that the Company expected that the pendant reheater would experience higher temperatures in the future than it had in the past. I do not know why the Company expected this. In any case, the replacement

[26] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.
[27] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.
[28] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.
[29] Detroit Edison's PAT review request form for PMP project 705, replacement of pendant reheater at Monroe 2, revision dated 4/21/10.

reheater was made of higher grade steels than the original had been, and this will increase the amount of time the tubes will be able to operate before experiencing failures.

(51) The Company's justification for the reheater replacement stated that:

> "The boiler tubes in the Reheat Pendants are failing. Unit 2 has experienced reheater pendant failures resulting in forced outages. Analysis done by the Boiler Tube Task Force predicts more frequent failures in the future. Objective would be to improve the reliability of Unit 2 by replacing the secondary reheater inlet and outlet pendants during the next Unit 2 major periodic outage."[30]

The Furnace Waterwall Tube Replacement

(52) In Monroe 2, all the walls of the boiler are lined with tubes, referred to as waterwall tubes. Waterwall tubes also form the division wall. This wall divides the furnace of the boiler into two equal spaces. The wall runs from the front of the furnace to the rear, half way between the two side walls.[31] In a well-designed boiler, waterwall tubes will last for many decades. They may cause some outages, but they will not wear out, that is, they will not reach a point where the number of tube failures per year increases substantially with the passage of time.

(53) Some units, especially units that were designed during the 1960s have furnaces that are too small. In such units, there can be corrosion on the outsides of the waterwall tubes, on the side of each tube that faces into the furnace. This fire-side corrosion reduces the thickness of the tube walls. Eventually, the walls can become so thin that the tube bursts. Such corrosion is generally concentrated in the lower part of the furnace, in the area around the burners. It is not a problem at the top of the furnace or in the top of the boiler or in the back pass. At some units, the rate of corrosion was increased as an unintended result of the installation of low NO_X burners. The industry has found that coating the outsides of the waterwall tubes with a corrosion resistant metal can reduce the rate of progress of the corrosion.

(54) From the Company documents I have seen, it appears that the waterwall tubes at Monroe 2 have been subjected to fire-side corrosion. In 2010, the Company replaced about 2,000 square feet of furnace waterwall tubes.[32] The Company described the replacement as

[30] Detroit Edison's PAT review request form for PMP project 705, replacement of pendant reheater at Monroe 2, revision dated 4/21/10.
[31] Figure 1 "Monroe Boiler Model" (EPA000011274).
[32] Since waterwall tubes line the walls of the boiler, it is customary to describe tube replacements in terms of the number of square feet of wall area that was replaced. Replacement tubes are often shipped to a plant in the form of

"[r]eplace damaged waterwall panels with new tubes which are clad with a corrosion resistant alloy."[33] The Company also stated that the replacement was to "[r]eplace waterwall surface internal to the Unit 2 boiler to improve reliability due to water tube failure from reduced wall thickness of Boiler Tubes."[34]

(55) The Company's justification for the waterwall replacement describes different areas to be replaced. These areas total about 1786 square feet.[35] During a recent EPA inspection, the Company said that the total area replaced during 2010 was about 2000 square feet.[36] This was not the first time the Company had replaced waterwall tubes at Monroe 2. During the planned outage of the unit in November-December of 2007 the Company spent $5.1 million in capital to replace some waterwall tubes.[37] This cost is somewhat less than what the Company planned to spend on the waterwall tube replacement in 2010. Based on the preceding, I concluded that during the planned outages in 2007 and 2010, the Company replaced a total of about 3500 square feet of furnace waterwall tubes.

(56) The Company stated that the 2000 square feet replaced in 2010 represented about 4% of the waterwall tube surface in the boiler. This means that the boiler has a total of about 50,000 square feet of waterwall surface. However, most of this surface is in parts of the boiler that are not susceptible to fire-side corrosion. Based on my experience, I estimated that something on the order of 10,000 square feet of the waterwall surface in Monroe 2 is susceptible to serious fire-side corrosion. This means that the 3500 square feet that the Company replaced in the last two and a half years is about one-third of the tubing that is susceptible to major fire-side corrosion.

(57) It may well be that the Company replaced some tubing prior to 2007, so that the total amount replaced has been more than 35% of the susceptible tubing. During a recent EPA inspection, the Company said that waterwall tubes are replaced frequently during planned and forced outages. [38] Of course, the Company would replace the more heavily corroded tubes first. The replacement tubing is coated with a corrosion-resistant alloy. The original tubing was not. All of the preceding means that the problem with fire-side corrosion

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panels. A panel is made up of many tubes lined up in parallel, with a small space between each pair of tubes. That space if filled with weld metal, which joins all the tubes into a single sheet or panel.

[33] Detroit Edison's PAT review request form for PMP project 5685, replacement of water wall panels at Monroe 2, revision dated 1/15/10.

[34] Detroit Edison's PAT review request form for PMP project 5685, replacement of water wall panels at Monroe 2, revision dated 1/15/10.

[35] Detroit Edison's PAT review request form for PMP project 5685, replacement of water wall panels at Monroe 2, revision dated 1/15/10.

[36] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.

[37] Fessler testimony, pages 19 – 21 says the work was done during the period July 2007 through June 2008. Data the Company reported to GADS shows only one planned outage during that time period – during November and December of 2007.

[38] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.

should become less severe with time. On the other hand, some level of on-going problems must be expected. During the 60 months prior to the 2010 planned outage, the unit experienced only two unplanned outages that were due to leaks in furnace waterwall tubes.

(58) Throughout the industry, when a major section of waterwall tubes is replaced at a unit, it often results in a substantial increase in the EAF of the affected unit. Monroe 2 only experienced two outages due to furnace waterwall tube failures in a five year period. This means that the possible increase in EAF due to the waterwall replacement is small. However, the replacement will prevent future decreases in unit availability that would have occurred had the waterwall tubing been allowed to continue to deteriorate.

(59) During a recent EPA inspection, the Company stated that the purpose of the waterwall tube replacement had been to reduce forced outages due to corrosion.[39]

THE OVERALL EFFECT OF THE THREE REPLACEMENTS ON THE UNIT

(60) During the 2010 planned outage at Monroe 2, the Company replaced all of the tubing in two components of the boiler and a substantial portion of the tubing in another component. Each of these three components had the following characteristics:

- Most of the tubing in the component was original, and had been in service for about 37 years;
- In recent years, the tubes had been leaking and thereby causing considerable amounts of outage time at the unit;
- The Company expected that the amount of outage time due to the tubes would increase with the passage of time (if the tubes were not replaced);
- The replacement tubing was new, so it did not have any of the damage that had accumulated in the original tubing during 37 years of operation; and
- The design of the replacement tubing was a considerable improvement over the original design.

(61) Based on this information (and on my experience and the experience of the industry), I concluded that the Company should have expected that the new boiler components would cause little or no outage time in the future, where the old tubes had caused considerable amounts of outage time in the past. The Company's justifications for the replacements indicate that it did expect considerable reductions in outage time.

[39] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.

(62) All else being equal, a reduction in the amount of outage time caused by the boiler components will result in an increase in the amount of time the unit is available to generate electricity. Each additional hour the unit is available is an additional hour it will operate. (As I said previously, Monroe 2 operates for every hour it is available to do so.) Each additional hour of operation results in an increase in the amount of electricity the unit actually generates. Generating more electricity requires the burning of more coal, which results in the emission of more pollutants.

(63) There is only one thing that could happen that would result in the availability of the unit not increasing after the replacements are implemented. This is that other components in the unit could cause more outage time in the future, offsetting the reduction in outage time due to the replacements. In the following section, I address the effect of the other components in the unit.

THE EFFECT OF OTHER COMPONENTS

(64) The vast majority of work that is done in a generating unit serves only to maintain the availability of that unit. One component fails and causes an outage in one month, and is fixed. Another fails and causes an outage the next month, and is fixed. In the absence of major upgrades, this pattern will tend to repeat. The availability of the unit will tend to go up and down with time depending on which components fail, and when they fail. However, the unit's long-term availability does not change with the passage of time.

(65) Despite the preceding, major improvements in a unit can cause long-term increases in that unit's availability. During the last 35 years, this has occurred at hundreds of units throughout the industry.

(66) There is very strong evidence that the replacements at Monroe 2 will increase the long-term availability of that unit. This evidence consists of:

- The potential for improvement;
- The magnitude of the replacements;
- Other improvements being made; and
- The Company's expectations.

(67) I address these four factors in the following sections.

The Potential for Improvement

(68) During the 60 months preceding the replacements, Monroe 2 achieved an average EAF of less than 81.0%.[40] It is my experience that generating units similar to Monroe 2 are capable of long-term EAFs in the range of 88 to 90%. Thus, the unit had considerable room for improvement.

The Magnitude of the Replacements

(69) Throughout the industry, most of the thousands of components in a unit cause no, or almost no, outage time. Some components cause small amounts of outage time. A few cause large amounts of outage time. By far the biggest cause of outage time is the boiler tubes. On average for the industry, boiler tubes cause nearly half of all the unplanned outage time at coal units. They are also responsible for some of the planned outage time. All of the preceding is also true for Detroit Edison's coal units. In 2008, a Company witness testified that:

> "The remaining 8.81% of fossil fleet unavailability in the July 2007 through July 2008 time frame was due to unplanned outages. Most of these outages were boiler related with the most predominant issue being boiler tube leaks in waterwall, superheater, reheater or economizer sections."[41]

(70) As I described in Appendix B, a single major boiler component that has worn out can cause more unplanned outage time than all of the thousands of other components in a unit combined. If a worn-out boiler component is not replaced, it can, in some situations, cause the unit to become completely inoperable. Thus, a single boiler component can cause substantial decreases in the availability of a unit. Replacing such a boiler component will then result in a substantial increase in the unit's availability.

(71) It could be that, after one boiler component was replaced, another component would become worn out. This other component might cause as much outage time in the future as the first component had caused in the past. In such a situation, the availability of the unit might not increase.

(72) For any coal unit, and especially for a unit as important as Monroe 2, I would expect that the Company periodically inspects and tests each boiler component. This would give the Company a reasonable expectation as to how long each component will be able to operate before it wears out, and begins causing increasing numbers of outages. The documents I

[40] This is the result of my calculation based on data the Company submitted to NERC GADS. Because of a problem with some of the Company's GADS data, I calculated an upper bound on the EAF. That was 81.0%. I estimate that the actual EAF for the unit was about 80.0%. Because I could not calculate that number precisely, I based my discussion on the conservative (upper bound) value.
[41] Fessler testimony, page 12.

have seen do not indicate which, if any, boiler components at Monroe 2 the Company expects to wear out in the near future. Even in the absence of this knowledge, I concluded that there is very little chance that wear-out of other boiler components could cause so much outage time in the future as to offset the reductions in outage time due to the replacements. This conclusion comes from the very unusually large magnitude of the work that was done during the 2010 planned outage.

(73) One can think of the Monroe 2 boiler as having six major components: the economizer, the horizontal reheater, the pendant reheater, the horizontal superheater, the pendant superheater, and the waterwalls. During 2007-2010, the Company completely replaced two of those six components, and replaced a substantial part of the susceptible portion of a third. Only if two or three of the other three components all wore out in the next five years might one expect that those components might cause as much outage time in the future as the three components that were replaced had caused in the past. There is some chance that one of the other three boiler components will wear out in the next five years. However, there is a greater chance that that will not happen. The probability that two or three of those three components will all wear out in the next five years is minute.

(74) Thus, the sheer magnitude of the work done during 2010 makes it extremely unlikely that wear-out of other components of the boiler would offset the reductions in outage times due to the replacements. Therefore, I concluded that the replacements should be expected to result in a considerable increase in the availability of the unit.

Other Improvements Being Made

(75) Monroe 2 is one of the Company's base-loaded coal units. In 2008, a Company witness testified that the Company expected the average EAF for all the base-loaded coal units would increase from 81.8% in 2007 to 83.5% in 2010. The expected improvement was due to a reduction in the impact of unplanned outages, from 12.0% in 2007 to 9.1% in 2010.[42] Based on these numbers, I calculated that the Company expected an increase in the average amount of planned outage time at the base-loaded coal units. This is not surprising. The Company planned major upgrades at many of the coal units during 2008 – 2010. One example of this is the major upgrades that the Company planned for, and actually implemented at, Monroe 2 in 2010. The 2010 planned outage at Monroe 2 was scheduled to last more than 12 weeks. This was longer than most planned outages at the unit. It resulted in the impact of planned outages at the unit being much higher in 2010 than it had been in previous years, including 2007.

(76) The Company's witness stated that the forecasts of plant availabilities were based on input from the plant staff and plant-headquartered reliability engineers, historical unit

[42] Fessler testimony, page 12.

performance, the known maintenance and operational status of each unit, and future planned outage schedules and work scope.[43]

(77) The Company's witness testified that the Company's efforts to improve the overall availability of its fossil units consisted of efforts to reduce the frequency of unplanned outages and efforts to reduce the lengths of planned outages. There is a section of this witness's testimony that describes the effort to reduce the frequency of unplanned outages. This section is devoted entirely to the effort to reduce the frequency of boiler tube failures.[44] This indicates to me that the Company's expectation of a reduction in the amount of unplanned outage time was mostly or entirely due to expected reductions in the frequency of boiler tube leaks. Since the expected increase in unit availability was due to the reduction in the amount of unplanned outages, it follows that the expected increase in unit availability was due mostly or entirely to a reduction in the number of boiler tube leaks. Based on my experience, the experience of the industry, and what I know about the condition of the Company's units, I concluded that the Company's expectations were reasonable.

(78) In addition to the program to reduce the number of boiler tube leaks, the Company had a program to improve the way it managed planned outages. The purpose of that effort was to "…decrease the duration and overall cost of planned outages without impacting the scope of work performed.[45] Given this effort, and the major upgrades that have been implemented, I concluded that the Company should expect that, once it has completed most of the major improvements at the base-loaded coal units, the average amount of planned outage time at those units will decrease. This will result in some additional increase in the average availability of the units.

(79) When asked to summarize the Company's efforts with respect to the availability of its fossil generating units, the Company's witness said that "Detroit Edison has invested significant capital and maintenance dollars over the last several years to maintain and improve generation unit availability…"[46] This testimony shows that the Company understands that the EAFs of its coal units can be increased. It also shows that the Company understands that capital improvements, including replacements of major boiler components, can contribute to increases in EAF.

(80) In summary, with respect to its fleet of fossil units, the Company expected that:

[43] Fessler testimony, page 12.
[44] Fessler testimony, page 13.
[45] Fessler testimony, page 13.
[46] Fessler testimony, page 14.

- The average availability of all the units would increase during the period from 2007 to 2010;
- This increase would be due entirely to a reduction in the amount of unplanned outage time;
- That reduction would be due mostly or entirely to a reduction in the number of boiler tube leaks; and
- Improved availability would result from investment of "…significant capital and maintenance dollars…"

(81) All of this is consistent with what I have seen at other units throughout the industry. Therefore, I concluded that the Company's expectations were reasonable.

(82) The Company's testimony I have quoted referred to the average for all of the Company's base-loaded coal units. Monroe 2 is one of those base-loaded coal units. Monroe 2 is essentially identical to three of the Company's other base-loaded coal units (Monroe 1, 3, and 4). The problems experienced by those other Monroe units, and the upgrades at those units, were generally similar to what was happening at Monroe 2. The Company implemented or planned similar component replacements at a number of other coal units. However, replacement of three major boiler components at one time, as was done at Monroe 2, is rare in the industry. In recent years, DTE has been making a major effort to upgrade its coal units. This means that the Company has been implementing more major improvements than I would normally expect. Even in these circumstances, replacement of three major boiler components at one unit at the same time is unusual.

(83) The Company's witness also listed some major capital projects that were being done at other coal units and did not involve boiler tube replacements.[47] There were also some replacements at Monroe 2 and at other coal units that did not involve boiler tube replacement. It is my experience that replacements such as these would either prevent future decreases in availability or result in small increases. At Monroe 2, there were two things that were done that would tend to increase the EAF of the unit. During the pre-replacement period, Monroe 2 had experienced a total of about 41 days of outage time due to failures of the main leads from the generator and of the main transformer. During the 2010 planned outage, the Company replaced the generator lead box. In addition, the Company bought a spare transformer that would serve Monroe 2 and similar units. These two actions should greatly reduce the chance of any future occurrence of the problems that caused the 41 days of outage time pre-replacement.

[47] Fessler testimony, pages 19-27.

(84) The preceding is all entirely consistent with the Company's testimony regarding the average of all its fossil units. Specifically, for all the units: availability would increase; the increase would be due to a reduction in the number of boiler tube failures; and this reduction would be largely due to replacement of boiler components that had worn out.

(85) The Company's witness testified that the availability of the base-loaded coal units would increase from 81.8% in 2007 to 83.5% in 2010. This increase did not include the improvements at Monroe 2. At the time of the testimony, Monroe 2 was scheduled for a planned outage of 12 weeks in 2010. This outage was longer than a usual major planned outage, because of the difficulties of replacing the economizer and the pendant reheater during the same outage. Largely as a result of this long planned outage, the Company forecast that the EAF for Monroe 2 in 2010 would only be 69%.[48] This means that other units would have experienced EAFs greater than the 83.5% average for all the units. The Company should have expected that the EAF of Monroe 2 would increase after 2010, when the effects of all the work that was done during the 2010 planned outage, including the three boiler tube replacements, would be felt, and when future planned outages would be expected to be shorter.

(86) The Company forecasted an average increase in EAF for the base-loaded coal units of 1.7 percentage points. This occurred even though some units, including Monroe 2, were expected to have lower availability in 2010, as a result of long planned outages to implement major upgrades. I concluded that, as Monroe 2 and other units completed their major upgrades, the average availability of these units would increase further.

<u>The Company's Expectations</u>

(87) As I stated earlier, during the five years (60 months) preceding the 2010 planned outage, Monroe 2 achieved an average EAF that was less than 81.0%. In a recent letter to EPA, the Company provided its forecasts of EAFs for Monroe for each of the calendar years 2010 through 2014. For the four years after the replacements (2011 through 2014) the average EAF is 84.3%. Thus, the Company itself was forecasting that the EAF for the unit will be at least 3.3 percentage points higher post-replacements than it had been pre-replacements. This is consistent with my expectations, as described in the preceding paragraphs.

(88) An increase in EAF of 3.3 percentage points corresponds to an additional 12 days of operation of the unit each year. Remember that Monroe 2 will emit more than 40 tons of

[48] DTE letter to EPA, dated 6/3/10.

SO_2 in a day. Thus, the increase in EAF that the Company expected was many times the increase needed to trigger PSD.[49]

(89) I also looked at the EAF and outage factors during the baseline periods selected by the Company for NO_X and SO_2 in its March 12, 2010 letter. Based on the information the company reported to GADs, I found the following:

TABLE 1 MONROE UNIT 2 BASELINE OPERATING STATISTICS			
Baseline	Planned outage factor	Equivalent unplanned outage rate (EUOR)	EAF
7/06 – 6/08	5.0	14.5	81.3
10/06 – 9/08	5.0	16.6[50]	79.3

Planned outage factor is the equivalent of the "periodic" row in the PROMOD data from the Company's June 3, 2010 letter, while EUOR is the equivalent of Random Outage Rate. Table 1 demonstrates that the expected improvement in EAF was due to a decrease in forced outages. The projected average EUOR for unit 2 for the years 2011 to 2014 was 8.7%, significantly less than the rate during the baseline periods.[51] As I discuss below, some or all of this improvement must be due to the project.

MY RESULTS REGARDING THE EFFECTS OF THE REPLACEMENTS ON THE AVAILABILITY OF MONROE 2

(90) During the spring 2010 planned outage, Detroit Edison replaced three boiler components. Specifically, the Company replaced:

- All of the tubing in the economizer component of the boiler;
- All of the tubing in the pendant reheater component of the boiler; and
- Some of the tubing in the waterwall component of the boiler.

(91) I looked at the data the Company reported to NERC GADS for the 60 months immediately preceding the boiler component replacements. All three replacements were

[49] As I said in the preceding, I believe that the actual EAF for the unit pre-replacements was about 80.0%. The difference between this pre-replacements value and the Company's forecasted post-replacement value of 84.3% is 4.3 percentage points. This corresponds to an additional 15.7 days of operation of the unit per year.
[50] The actual equivalent unplanned outage rate is likely slightly higher and the actual EAF slightly lower than I show here for reasons discussed elsewhere in this declaration.
[51] Company's June 3, 2010 letter to EPA.

done during the planned outage that started in March of 2010. Therefore, the 60 months preceding the replacements were from March of 2005 through February of 2010.

(92) Table 2 shows information about those outages and deratings that occurred during the 60 months pre-replacements and were due to problems with the tubes that were replaced. The information in Table 2 all came from data that the Company reported to NERC GADS.

TABLE 2
OUTAGES THAT WERE DUE TO BOILER TUBES THAT WERE REPLACED IN SPRING 2010

Event Start Date	Event End Date	Outage Duration (hours)	Derating EFPH	Outage Cause
4/3/06	4/9/06	124.8		Economizer tube leak
4/17/06	4/19/06	54.9		Economizer tube leak
4/22/07	5/7/07		11.4	Economizer slagging or fouling
5/7/07	5/9/07		1.1	Economizer slagging or fouling
5/9/07	5/11/07		2.2	Economizer slagging or fouling
5/11/07	5/12/07		1.6	Economizer slagging or fouling
5/12/07	5/15/07		2.1	Economizer slagging or fouling
5/15/07	5/23/07	205.0		Economizer slagging or fouling
8/7/07	8/14/07		8.1	Economizer slagging or fouling
2/12/08	2/15/08	75.9		Economizer tube leak
3/23/08	4/2/08	237.3		Economizer tube leak
5/9/08	5/13/08	83.0		Economizer tube leak
6/9/08	6/14/08	123.0		Economizer tube leak
7/31/08	8/3/08	68.6		Economizer tube leak
8/27/08	9/1/08	115.0		Economizer tube leak
5/19/09	5/24/09	120		Secondary reheater tube leak
9/6/09	9/10/09	85.8		Economizer tube leak
1/25/10	1/29/10	113.9		Economizer tube leak

(93) I concluded that the Company should have expected that the probability of outages due to similar problems would be very low post-replacements. This conclusion was based largely on the experience of the industry with similar boiler component replacements. That experience is that new boiler components usually operate for at least 10 or 20 years, and often longer, with a low rate of occurrence of tube leaks.[52] Because of this

[52] Sometimes, there may be some failures in the weeks immediately after a unit starts up with a new boiler component. When they occur, such failures are usually due to defects in welds that were made when fabricating or installing the new section of tubes.

experience, utilities usually base their economic evaluations of component replacements on an expectation that the new tubes will not cause any outage time, at least for the first 10 or 20 years of operation. Statements in DTE's justifications for the three replacements, which I have cited elsewhere, indicate that the Company also expected little or no outage time due to the new tubes post-replacements.

(94) Table 3 shows information about four other outages that occurred during the 60 months pre-replacements. This information also comes from data that the Company reported to NERC GADS.

TABLE 3
OUTAGES THAT WERE PROBABLY DUE TO BOILER TUBES THAT WERE REPLACED IN SPRING 2010

Outage Start Date	Outage End Date	Outage Duration (hours)	Outage Cause
10/2/05	10/9/05	157.9	First reheater tube leak
1/16/06	1/20/06	99.6	Furnace wall tube leak
8/14/07	8/18/07	93.4	First reheater tube leak
12/6/09	12/11/09	114.6	Furnace wall tube leak

(95) I concluded that it is likely that some or all of these four outages were due to problems with tubing that was replaced during the planned outage of the unit in the Spring of 2010. However, the information I had about those outages was not detailed enough for me to be reasonably certain. In the following paragraphs, I describe why I am reasonably certain about the outages listed in Table 2, and not so certain about those listed in Table 3.

(96) One of the three replacements at issue involved replacing all of the tubing in the economizer of Monroe Unit 2. The Company said that the economizer was experiencing fouling of the tubes (plugging of the spaces between some tubes with coal ash) and also tube leaks. The Company reported that 10 of the 12 outages listed in Table 2 were caused by leaks in economizer tubes. It reported that one of the outages and all of the deratings were due to fouling of the economizer tubes. Since the Company replaced all of the economizer tubes in 2010, I concluded that all of the outages and deratings that are listed in Table 2 and were due to leaks or fouling in the economizer were due to problems with the tubes that were subsequently replaced.

(97) Among all the coal units in the US, there are many different arrangements of reheaters. The most common arrangement is that steam first passes through one or more horizontal banks of tubes, called the horizontal or primary reheater, and then through one or more

pendant banks, known as the pendant or high temperature reheater. NERC GADS has two cause codes for reheater tube leaks. These are 1060 "first reheater tube leaks", and 1070 "second reheater tube leaks". When I developed the NERC GADS cause codes 30 years ago, I intended that leaks in the horizontal reheater would be reported as cause code 1060 and leaks in the pendant reheater would be reported as cause code 1070. Some data reporters report as I had intended. Others report all reheater tube leaks as cause code 1060. This is because of an ambiguity in the way I wrote the cause code list.[53] At least some people at Detroit Edison took this view. During a recent EPA inspection, the Company stated that it does not make any distinction between the first and second reheaters and was not clear why it was identified as such in the GADS data.[54]

(98) The Company reported three outages due to leaks in the reheater tubes. Two of these were reported as having been due to the first reheater, and one due to the second reheater. Since the Company replaced the pendant reheater and not the horizontal reheater, I expect that most of the leaks in the reheater would have been in the pendant component.

(99) Given the preceding, I concluded that it is likely that all three of the outages that were reported as having been due to reheater tube leaks were actually due to leaks in the pendant reheater. I could be reasonably certain that the outage that was reported as having been due to the secondary reheater was in fact due to a leak in the pendant (secondary) reheater. I could not be so certain that the two outages that were reported as having been due to the first reheater were really due to the pendant reheater. Therefore, I included them in Table 3.

(100) The other replacement involved a portion of the waterwall tubes in the lower portion of the furnace component of the boiler. The Company reported two outages during the 60 months that were due to leaks in furnace waterwall tubes. Of course, the Company would replace those portions of the tubes that had deteriorated the most, and were most likely to cause outages. Because I could not be reasonably certain that the leaks that caused the two outages were in tubing that was replaced in the spring of 2010, I listed those two outages in Table 3.

[53] In a small number of units, steam is reheated twice. For those units, there is a first reheater, with a first and a second section, and a second reheater, also with a first and second section. At units such as Monroe 2, which has only one reheater, some data reporters regard the entire reheater as the first reheater. They rightly say that the unit does not have a second reheater.

[54] EPA notes on inspection of Monroe 2 on 6/2/10, notes dated 6/3/10, page 3.

THE UTILIZATION OF THE INCREASED AVAILABILITY OF MONROE 2

(101) If a unit is able to operate for some number of additional hours per year, the potential additional generation (in MW-hrs) is the product of the unit's capability times the number of additional hours. For example, Monroe 2 has a capability of 795 MW – that is the maximum output the unit can generate consistently when all equipment is working normally. If Monroe 2 operates at full power for an additional 100 hours, it will generate an additional 79,500 MW-hrs of electricity (795 * 100 = 79,500).

(102) Monroe 2 always operates when it is able to operate, that is, it always operates when it is available. However, it does not always operate at full power – it does not always operate at its capability. Sometimes the unit is derated – that is, it is limited to something less than full power due to some equipment problem. At other times, the unit is operated at lower power levels because DTE's customers do not want all the power the unit can generate. This is especially true late at night.

(103) One measure of the performance of a generating unit is the output factor (OF). For a given period of time, the OF for a unit is the power the unit actually generated divided by the power it could have generated had it always operated at its capability (full power) when it is operating. For example, let us say that, for some time period, the OF for Monroe 2 was 80%. This means that, for all the hours the unit operated, its average output was 80% of full power. For Monroe 2, full power is 795 MW, so 80% of full power is 636 MW.

(104) During the 60 months pre-replacements, the OF for Monroe 2 averaged less than 82.6%.[55] It does not show any trend to increase or decrease during that time period. I also calculated OF for the baseline periods selected by the company and found a OF of 80.8% for the NO_X baseline period and an OF or 81.5% for the SO_2 baseline period.

(105) The Company's projections for the years post-replacements show OFs increasing steadily, from 88% in 2010 to 96% in 2014. For the four years after the replacements, 2011 through 2014, the Company's forecasts show an average OF for Monroe 2 of 92%.[56]

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[55] The company spreadsheet "Presentation Steam Unit Summary PSCR" produced as part of its supporting materials for the September 2009 PROMOD run gives the capacity factor and EAF for the unit for each calendar year 2005 through 2009. (2009 represent a mix of actual data and a projection, since the analysis was submitted in September 2009). For these give years, I calculated the average CF and the average EAF. The ratio of CF to EAF was 82.6%. Because the Company reported deratings of the unit during those five years, the OF for the unit must be less than CF/EAF. Based on the preceding, I concluded that the OF for the unit pre-replacements was certainly less than 82.6%.

[56] DTE's letter dated 6/3/10 gives values for the "loading factor" for each year from 2010 through 2014. Based on other data given in that letter, I calculated that loading factor is the same as OF.

(106) For sake of illustration, let us say that the average OF for the unit was 83% pre-replacements and was expected to be 92% post-replacements. Let us further say that the unit is expected to be available (and, therefore, to operate) for an additional 100 hours per year in the future as a result of the replacements.

(107) If the OF for the unit does not increase, the additional 100 hours of availability will result in additional generation of 65,985 MW-hr per year (795 * 100 * 0.83 = 65,985). If the OF increases to 92%, the additional generation will be 73,140 MW-hr per year. (Note that Dr. Sahu calculated the increase in availability that would be expected to result from the boiler tube replacements. The 100 hours I am using here is simply for illustration, and was chosen because it is a round number.)

(108) In the preceding illustration, the entire 73,140 MW-hr per year of additional generation was due to the boiler tube replacements – none of the increase would have occurred but for the projects.[57]

(109) It is logical to conclude that if unit availability increases, generation will also increase. Projects such as the component replacements at issue here are justified based on economics: the cost of the work is weighed against the additional income to be generated from selling additional electricity. It would make no sense to do these types of projects if the utility did not anticipate operating the unit more in the future.

(110) I understand that Dr. Sahu calculated increases in emissions based on the OF that the company experienced in the respective baseline periods. Those OFs are significantly less than the 92% the Company forecast for the four years after the replacements. This will cause the emissions increases calculated by Dr. Sahu to be conservative – they will be lower than what would realistically be expected.

[57] In the illustration, 65,985 MW-hr of additional generation was due solely to the replacements – it would have occurred even if the OF for the unit did not increase. The other 7,155 MW-hr of additional generation was due to the combined effects of the replacements and the increase in OF. Both the 65,985 and the 7,155 are attributable to the replacements. Neither would have occurred but for the replacements.

THE COMPANY'S TREATMENT OF THE EFFECT OF INCREASED EAF ON GENERATION

INTRODUCTION

(111) The Company recently submitted results of PROMOD projections that it submitted to the Michigan Public Service Commission in September 2009. Some of the key inputs to those projections were forecasted future values of the EAF for Monroe 2.[58] As I described previously, the Company's forecasted EAFs for the unit are substantially higher than the actual EAF the unit achieved during the 60 months pre-replacement.[59] In terms of the EAFs for Monroe 2, the three boiler replacements are far and away the most significant things that have happened to the unit in recent years. Nonetheless, in its June 1 and 3, 2010 letters to EPA, the Company is now claiming that it forecasted future EAFs for the unit, and forecasted that the unit's EAFs would increase, without any consideration of the fact that the replacements were being done.

(112) The Company's present claim is inconsistent with its own statements two years ago. It is also inconsistent with the basic logic of generating unit availability. I address those two issues in the following sections.

PRIOR COMPANY CLAIMS

(113) Two years ago, the Company was trying to justify its plans to spend hundreds of millions of dollars on major upgrade replacements at its fossil units. Much of the money was to be spent on boiler component replacements, including replacement of the economizer and the pendant reheater at Monroe 2. In that context, a Company witness testified that the Company expected substantial increases in the EAFs of its base-loaded coal units, one of which is Monroe 2. Moreover, information in that witness's testimony shows that all or most of the expected increase in EAF was due to boiler component replacements at those base-loaded coal units.

(114) Two years ago, the Company's position was that it had forecasted that EAFs would increase, as a result of major upgrades. In forecasting future EAFs at that time, the Company must have taken account of the expected benefits of those major upgrades, including the boiler component replacements. If it had not done so, then its justification for the upgrades would have been very misleading.

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[58] DTE letter to EPA, dated 6/1/10.
[59] See discussion earlier in this declaration.

(115) Two years ago, the Company wanted to convince state regulators that its forecasts of future EAF were thorough. At that time, the Company witness testified that:

> "The Detroit Edison forecasted plant availabilities are based on input from Plant Staff and plant-headquartered Reliability Engineers, historical unit performance, known maintenance and operational status of each unit, and future planned outage schedules and work scope." [60]

(116) Monroe plant staff and plant reliability engineers would have known about the upcoming boiler component replacements on Unit 2. They would have known that, in terms of effects on the future EAF, these replacements were far and away the most important thing that was happening to the unit. When a single boiler component at any unit wears out, this becomes one of the biggest maintenance issues at that unit. At Monroe 2, three boiler components had worn out. Even the most cursory consideration of the "…known maintenance and operational status…" of the unit would have had to include the condition of the boiler tubes. Worn out boiler components require a large amount of work during each planned outage. Even the most cursory consideration of the "…future planned outage schedules and work scope…" would have had to include the condition of the boiler tubes.

(117) Despite all the preceding, the Company now claims that its forecasts of future EAFs of the unit were made without any consideration of the major upgrades.

(118) Another way of looking at this issue is as follows. The Company might simply have forecasted that the future EAF of the unit would be the same as the historical value. Some utilities do that, without any consideration of the condition of the unit in question. However, the Company forecast that the EAF of Monroe 2 would increase substantially. This must have been based on some consideration of the condition of the unit. Even the most cursory consideration of the condition of the unit must have taken account of the replacements.

THE LOGIC OF GENERATING UNIT EAF

(119) For PSD, the Company could have forecast how much future emissions would be increased as a result of the replacements. One way to do that would have been to forecast the future emissions based on the Company's baseline expectations and the EAF for Monroe 2 that was expected if the replacement was not implemented, and then make a second forecast based on all the same assumptions except that the EAF for Monroe 2 would be that which was expected if the replacement was implemented. In order to

[60] Fessler testimony, page 11.

isolate the effect of the replacement, the two forecasts should have been based on all the same assumptions, except that one forecast would be based on the replacements being done and one on the replacements not being done.

(120) The Company should have expected that the boiler components would cause hundreds of hours of outage time per year in the future if they were not replaced.[61] It also should have expected that those components would cause little or no outage time per year in the future if they were replaced.[62] Because of the preceding, any forecasts the Company would make that took account of the replacements would show more outage time per year in the future if the replacements were not done than they would show if the replacements were done.

(121) There would be hundreds more hours of outage time per year if the replacements were not done than there would be if they were done. There would have been hundreds fewer available hours per year but for the replacements. This means that the forecast EAF would be at least four percentage points lower if the replacements were not done than it would be if they were.[63]

(122) The Company forecasted that the EAF of the unit would increase. It now suggests (in the June 1, 2010 letter to EPA) that this forecast was made without any consideration of the replacements. Even without considering the effects of the replacements, the Company forecasted an increase in EAF. I have just shown that consistent forecasts will always show the future EAF being higher if the replacements are done than if they are not. The preceding leads to the following conclusions:

- Had the Company forecast the future EAF of Monroe 2, taking account of the expected effect of the replacements, that forecast future EAF would inevitably have been higher than the actual historical EAF;
- Had the Company forecast the future EAF of Monroe 2, assuming that the replacements would not be implemented, that forecast future EAF would inevitably have been lower than the forecast EAF taking account of the replacements being done;

[61] The events listed in Table 2 alone caused an average of about 287 hours of outage time at Monroe 2 per year, during the five years (60 months) pre-replacement. For reasons I describe earlier in this declaration, this almost certainly understated the amount of outage time that was being caused by the three boiler components pre-replacement. The Company said that the amount of outage time due to these tubes was increasing with time. Given that increase, and the experience of the industry (that the number of leaks in a worn-out boiler components increases with time) the Company should have expected that the existing tubes would cause more outage time in the future than they had done in the past.

[62] This is based on statements in the Company's justifications for the replacements. It is consistent with industry experience and expectations, as I described elsewhere in this declaration.

[63] Three hundred and fifty additional hours of outage time per year will reduce the EAF for a unit by 4.0% (100 * 350 / 8766 = 3.99 percentage points).

- The forecast EAF assuming no replacements might still be higher than the actual historical EAF. In that case, some of the forecast increase in EAF would be due to the replacements, and some would not. That is, but for the replacements, there would still have been an increase in EAF but the magnitude of that increase would have been smaller; and
- The forecast assuming no replacements might be lower than the actual historical EAF. In that case, all of the forecast increase would be due to the replacements.

(123) The Company expected an increase in EAF. Had it accounted for the effects of the replacements, it would still have expected an increase. But for the replacements, the magnitude of the expected increase would have been smaller, and might have been negative. Some or all of the expected increase in EAF was due to the replacements – it would not have been expected but for the replacements.

THE COMPANY'S "CAPABLE OF ACCOMMODATING" ARGUMENT

(124) The Company forecasted that Monroe 2 would generate more power post-replacements than it had done pre-replacements. It claims that the expected increase in generation was all due to increased demand on the unit, and none of the increase was due to the replacements. One of the arguments it uses to support this claim involves the amount of generation the unit was capable of accommodating pre-replacement.

(125) The Company calculated how much power it says Monroe 2 could have generated during the pre-replacements baseline period it selected. It then calculated how much power it had forecasted that the unit would actually generate post-replacements. The Company claims that the forecasted actual generation post-replacement is less than the possible generation pre-replacements. It seems to claim that this alone proves that the forecast increases in generation were not due to the replacements. There are two things wrong with this argument:

- The Company's calculation overstates the amount of power the unit could have generated pre-replacements; and
- Even if one accepts the Company's calculation, its argument is illogical.

EAF OVERSTATES THE AMOUNT OF ELECTRICITY THE UNIT COULD HAVE GENERATED

(126) The Company's calculation of possible pre-replacements generation is based on the assumption that the EAF of a unit represents the output that unit could have produced had it been asked. This is not true. The reality is that EAF overstates how much a unit could have generated, often by a large amount. For all but a few of the hundreds of units I have looked at in the last 35 years, the reported EAF overstated the amount of electricity the unit actually could have generated.[64] Depending on the unit, a reported EAF will overstate possible generation by somewhere between two percentage points and as much as 10 to 15 percentage points.

(127) The EAF for a unit is calculated based in part on the assumption that, whenever the unit was operating, it could have operated at 100% power, or at the power level to which it was limited by any reported deratings. The EAF of a base-loaded unit, such as Monroe 2, overstates what the unit could actually have generated, because utilities almost never report all the deratings that were experienced by a unit.

(128) Whenever the output of a unit is limited to less than 100% of full power, the unit is said to be derated. Each derating reduces the amount of electricity a unit can generate. Each time a derating exists but is not reported, the reported EAF overstates the amount the unit could have generated if asked. Consider a unit that has a physical problem that limits its output to 80% of full power. Because of reduced demand, the unit is actually being operated at 70% of full power. If demand increased, the unit could actually produce an additional 10% of full power (from 70% up to 80%). If the derating was not reported, EAF would be calculated based on the assumption that the unit could have generated an additional 30% of full power (from 70% all the way up to 100%). As a result of failure to report some deratings, the EAF for a unit will substantially overstate the amount of additional electricity that unit could have generated.

(129) It is my experience that few, if any, units report all deratings to GADS. Personnel at most units inadvertently overlook some deratings when reporting to GADS. Moreover, utilities often deliberately fail to report some kinds of deratings: particularly work done during low demand periods and power ramps before and after outages.

(130) During times when demand is low, and the output from a unit is reduced, utilities will often do maintenance on equipment, especially coal handling equipment. This work is usually not reported as causing deratings. However, had the unit actually been asked to

[64] Utilities do not report EAF directly. EAF is calculated by applying a standard formula to data that utilities do report. For simplicity, I refer to reported EAFs. This should be understood to mean "EAFs calculated by applying the standard formula to the data reported by the utility".

run at full power during those periods, it would not have been able to do so, since the maintenance work would still have been needed.

(131) When a unit starts up after an outage, its output is initially low and then increases (ramps up) over a number of hours. During those hours following each outage, the unit is limited to less than full power – it is derated. However, most utilities do not report these startup ramps. Similarly, units are often ramped down in power before an outage. Again, the unit is derated. Most utilities do not report these deratings.

(132) During the pre-replacements time period, Monroe 2 experienced many outages. The Company did not report any startup or shutdown ramps associated with any of those outages, even though such ramps must have existed. This alone means that the reported EAF for Monroe 2 substantially overstates the amount of electricity it would have been able to generate, had it been asked. To the extent that the Company failed to report other deratings, as all utilities do to some extent, the reported EAFs further overstate the amount the unit could have generated.

(133) In looking at other units that are similar to Monroe 2 throughout my career, I have found that the failure to report startup and shutdown ramps alone causes EAF to overstate possible generation by around two percentage points. I have also found that failure to report other deratings often causes the reported EAF for a unit to overstate possible generation by another two percentage points, and sometimes considerably more. Based on the preceding, and my experience, I concluded that the reported EAFs for Monroe 2 most likely overstate the amount the unit could have generated pre-replacements. The magnitude of this overstatement is most likely in the range of three to four percentage points of EAF.

(134) In any event, I calculated the EAF for the unit for the company's selected NO_X and SO_2 baseline periods. For the SO_2 baseline period, the EAF was 81.2% and for the NO_X baseline period it was slightly less than 79.3%. As I said earlier, those EAFs substantially overstate how much power the unit could have generated during those periods. However, even accepting those numbers, these EAFs are less than what the company forecast to generate in 2013. Thus, the unit was *not* capable of accommodating the additional generation forecast.

THE COMPANY'S ARGUMENT IS ILLOGICAL

(135) Figure 2 shows a typical week in the life of a typical base-loaded coal-fired generating unit. This figure is highly stylized and does not represent any specific unit exactly. Nonetheless, it gives a realistic representation of how such a unit is operated.

(136) The system dispatcher always wants this unit to operate. Therefore, the unit always operates when it is able – whenever it is not broken. On Wednesday, this unit could not run – it was broken. It had a leak in a boiler tube. Had the unit been able to run, it would have run. It did not run, solely as a result of that boiler tube leak. On each of the other six days in the week, the unit was able to run, so it did run.

(137) On each day, the dispatcher wants the unit to run at 100% power during the day, when customers are using a lot of electricity, and at 54% of full power at night, when customers are using a lot less. In Figure 2, the amount of electricity generated through the week is shown in yellow.

(138) What would happen if I undertook the replacement of the worn-out boiler tubes, so there would be no outages due to those tubes in the future? Pre-replacement, the unit was available to operate six days per week, so it did operate six days per week. Post-replacement, it will be available to operate seven days per week, so it will operate seven days per week. During that additional day (Wednesday in our stylized example) the dispatcher will want the unit to operate at 100% power during the day and at 54% power at night; and that is what it will do. Figure 3 shows the situation post-replacement. Post-replacement, the unit runs the same for the six days; and generates the same amount of power – still shown in yellow. In addition, the unit now runs on Wednesday as well. Of course, it generates more power – shown in red. The total power generated post-replacement is more than the generation pre-replacement. The increase is due solely and entirely to the replacement.

(139) Despite the preceding, one could apply the Company's argument and conclude that the replacement did not cause the increase in generation. Following the Company's argument, one would look at Figure 2. One would note that, pre-replacement, the unit could have generated more power than it actually did. To do this, the unit would have had to operate at 100% power at night, when no one wanted that added power. Running the unit at full power at night would have been wasteful and irresponsible; but the Company says it could have done so.

(140) Pre-replacement, the unit could have generated more than it did (the yellow in Figure 2), by running at full power at night. It did not do that. Post-replacement, the unit could have generated more than it did (the yellow plus the red in Figure 3), by running at full power at night. It did not do that. Pre-replacement and post-replacement, the unit ran the same way whenever it was able to run. In other words, the demand on the unit did not change, and did not cause the increase in generation. The increase was caused by the replacement.

(141) The Company's argument is like Mr. X who commits a crime and then claims he can prove that he did not do it. His proof is that he can show that Mr. Y could have done the deed. Mr. Y did not commit the crime; Mr. X did it. Nonetheless, Mr. X claims that the mere fact that Mr. Y could have done it proves that he did not do it. The Company's argument really is that simple – and that illogical.

(142) Finally, let us consider what would happen to the unit post-replacement if the boiler component was replaced and the demand on the unit increased, so the unit operated at higher power levels at night. The result is shown in Figure 4. The total generation is now greater – the total of the yellow and the red and the green. The additional red power was due solely to the replacement. Whether demand increased or stayed the same, the replacement would cause the added red power. The green power on all the nights but Wednesday is due solely to increased demand. Whether the replacement was done or not, the increased demand would cause the added green power (on the six days). The green on Wednesday is additional power that would only be generated if demand increased and the replacement was implemented.

(143) In the case of Monroe 2, the Company expected that the unit would experience an increase in EAF and an increase in demand. Figure 4 shows an example of a situation when EAF increased and demand on the unit also increased. In such a situation, it is always true that the generation by the unit will increase. It is also always true that some of the increase in generation will be due solely to the increase in EAF and some will be due to solely to the increase in demand. A small amount of the increase will be due to the combined effects of the increased EAF and the increased demand.

(144) In a situation when both EAF and demand on the unit increase, there will always be an increase in generation. In such a situation, some of the increase in generation is always due to the increase in EAF – the increase in generation would be less but for the increase in EAF. Despite what the Company claims, it can never be true that all of the increase in generation is due solely to the increase in demand.

I declare under penalty of perjury that the foregoing is true and correct.

Robert H. Kopple

Executed on July 23, 2010 in Boulder, Colorado

APPENDIX A

QUALIFICATIONS AND EXPERIENCE OF

ROBERT H. KOPPE

EMPLOYMENT HISTORY

1968-1974 - Consolidated Edison Company of New York

For his first two years with Con Ed, Mr. Koppe was an engineer in the company's Nuclear Engineering Division. For the next four years, he was manager of that Division and was responsible for licensing, safety analysis and engineering for safety-related projects for Con Ed's five nuclear units. His responsibilities included design review and licensing for the Indian Point 2 and 3 turnkey units; design review of modifications and additions to the three Indian Point units; and modifications, analysis, and engineering support for the nuclear portions of the Indian Point 1 and 2 units during operation. He participated extensively in the design, safety analysis, and licensing for the proposed Verplank 1 and 2 BWR units.

1974-1994 S. M. Stoller/Hagler, Bailly, Boulder, CO

In 1974, Mr. Koppe was employed by the Power Division of the S. M. Stoller Corp., which was purchased by RCG/ Hagler, Bailly in 1989. During his 20 years with the Division, he was deeply involved in the following areas of:

- developing data bases for power plant performance and power plant equipment reliability,
- analyzing the performance of power plants and power plant equipment,
- developing power plant performance standards,
- reducing power plant operating costs, and
- auditing/reviewing power plant performance and costs.

He is the author of numerous reports on these subjects and has presented expert testimony on them before regulatory bodies in Maine, Massachusetts, New York, Pennsylvania, Delaware, Maryland, Virginia, North Carolina, Louisiana, Texas, Oklahoma, Wisconsin, Ohio and Ontario, and before several licensing boards of the Nuclear Regulatory Commission. He has also presented expert testimony in two civil suits.

1994-present, Koppe Consultants Inc., Boulder, CO

In 1994, Mr. Koppe left Hagler Bailly and formed his own consulting company. He has continued with the work he did at Hagler Bailly.

EDUCATION

- State University of New York, College of Forestry, BS, Wood Products Engineering, 1965.
- Ohio State University, MS, Nuclear Engineering, 1966.

In addition, Mr. Koppe completed all course work toward a Ph.D. in Nuclear Engineering at the Massachusetts Institute of Technology.

PROFESSIONAL EXPERIENCE

The following are some of the projects in which Mr. Koppe has had a major role, either as project manager or as a principal contributor. These projects all involved fossil-fired (primarily coal) power plants. Mr. Koppe worked on many other projects that involved nuclear power plants.

POWER PLANT PERFORMANCE TARGETS

- Studies to develop performance targets (Capacity Factor, Equivalent Availability Factor and Heat Rate) for many nuclear and fossil power units, including:
- nine fossil and four nuclear units owned by Atlantic Electric,
- eleven fossil and four nuclear units owned by Delmarva Power and Light,
- seven fossil units owned by Metropolitan Edison,
- seven fossil units owned by Philadelphia Electric,
- two fossil units and one nuclear unit owned by Southern California Edison,
- one nuclear and five fossil units owned by Rochester Gas and Electric,
- five fossil and four nuclear units owned by Virginia Power, and
- twelve fossil units owned by TransAlta (also included targets for O&M and capital additions costs).

AUDITS, REVIEWS AND STUDIES OF INDIVIDUAL UTILITIES, POWER PLANTS OR POWER PLANT OUTAGES

- An evaluation, for Virginia Power, of the performance of its five largest coal-fired units. The evaluation looked in detail at many recent or planned improvements in plant design and maintenance, and quantified the improvements in the performance of the units expected as a result.

- An evaluation, for Georgia Power, of its programs to improve the performance of its nuclear and fossil units, especially the Vogtle (nuclear) and Scherer (coal) units. The evaluation considered both design improvements and improvements in operations and maintenance, and quantified the costs and expected benefits of scores of improvements.

- An evaluation, for the Public Staff of the North Carolina Public Utilities Commission, of the life extension program proposed by Duke Power Company for eleven coal-fired units. The evaluation looked at the need for the life extension program, the improvements in the performance of the units expected to result from the program, and changes in program costs and plant outage times that might result if the program were carried out using schedules considerably different from the one proposed by Duke.

- An audit, for the New York Department of Public Service, of the availability and heat rate of Rochester G & E's one nuclear and five coal units. The audit included (1) comparison of RG&E's units with similar units in the industry, (2) evaluation of the management of the units and of various RG&E programs (such as maintenance, outage planning and plant modifications) as they affected availability and heat rate, (3) identification of programmatic or hardware charges that might improve availability or heat rate, and (4) prioritization of a number of proposed improvements based on cost-benefit evaluations of each improvement.

- An assessment, for the City of Cincinnati, of the costs that had been incurred to convert the Zimmer nuclear plant to coal, and a comparison of those costs to the anticipated costs of constructing a coal unit at a "greenfield" site. The "conversion" involved only a very modest use of equipment from the nuclear plant. The resulting plant is essentially a duplicate of the AEP design for 1300 Mw supercritical coal units.

- An assessment, for Houston Light and Power, of its proposed program for life extension of two older gas-fired units. These units had been mothballed and were being considered for refurbishment and life extension. The assessment focused on the scope of refurbishment that would be required and the performance (Equivalent Availability Factor) that could be expected from the units following that refurbishment.

- A study, for the California Department of Water Resources, of the expected capacity factor for a new coal-fired unit.

- An evaluation, for the Municipal Electric Association in Ontario, of Ontario Hydro's long term plans for its generating stations, which included 20 Candu-type nuclear plants and a number of coal-fired plants.

- Estimates, for an independent power producer, of the costs to build and operate a number of different power plants including a coal-fired plant, a combustion turbine plant and a combined cycle plant.

- Evaluations, for two different independent power producers, of the heat rates of their cogeneration facilities. The emphasis of these evaluations was the ability of the facilities to meet PURPA requirements for a QF.

- An evaluation, for Philadelphia Electric, of its coal plants at Eddystone and Cromby. The evaluation focused on performance changes to be expected as a result of new emissions control systems and many changes in plant design and operations.

- An assessment, for TransAlta (Alberta), of the expected performance and costs of its 12 coal power plants throughout their remaining lives. The assessment looked in detail at (1) historical performance and costs of the 12 units and of peer units throughout North America, (2) an assessment of the material condition of the plants done by an architect/ engineer, and (3) review of expected modifications and upgrades of plant equipment throughout remaining life.

STUDIES OF INDUSTRY WIDE POWER PLANT EXPERIENCE

- An analysis, for EPRI, of data in the North American Electric Reliability Council's Generation Availability Data System (NERC-GADS) to determine the impacts of various problems on fossil plant performance as a function of design and operating characteristics. This study was to assist EPRI in R&D planning and was not published.

- A study, and a later update, for EPRI, of the performance of nuclear and large fossil generating units and of the causes of outages and deratings at those units. The studies looked in detail at:
- how performance varied as a function of such factors as the size, age, and vintage of a unit;
- the impacts of each plant system and component on plant availability;
- the frequencies and duration of outages due to major problems; and
- the effects of various design and operating conditions on the frequencies of problems.

- A study, for EPRI, covering the historical performance of fossil-fired units and the relationship of this performance to major unit characteristics such as size, age, vintage, fuel, steam pressure, etc. The study (based on analysis of NERC-GADS data) covered all units sized 200 Mw and larger over the period from 1965 through 1984. The analysis examined both unit and system/component performance. (EPRI Report CS-5627)

DEVELOPMENT OF POWER PLANT DATA BASES AND RELIABILITY IMPROVEMENT PROGRAMS

- Preparation of the Generating Availability Data System (GADS) reporting manual for the North American Electric Reliability Council. Presentation of a series of workshops to teach utility personnel responsible for data reporting how to use the new reporting system.

- A series of six studies, for EPRI, to determine how power plant reliability/availability data systems could be improved. Interviews were conducted with utilities, equipment suppliers, architect/engineers, government agencies and operators of existing data systems -- as well as many non-utility organizations -- to determine what data were being collected, the uses being made of that data and the most effective ways to collect and to use data.

- Development, for EPRI and NERC, of a series of detailed examples showing use of NERC GADS data in utility decision making (EPRI Report NP 2167).

- Presentation of workshops sponsored by the Electric Power Research Institute on basic techniques in availability engineering, emphasizing use of NERC-GADS data. (EPRI Report NP-2166)

APPENDIX B:
GENERAL DISCUSSION OF THE PERFORMANCE OF COAL-FIRED ELECTRIC GENERATING UNITS AND MY METHODOLOGY FORANALYZING THAT PERFORMANCE

COAL UNIT OPERATION

In this Appendix, my descriptions of the industry are based on a combination of my experience working at individual units, my experience analyzing data on the industry, and industry-wide design data reported to GADS.

No generating unit can operate all the time. Every unit must shut down at least occasionally to overhaul equipment or to repair equipment that has failed. When a unit is shut down to overhaul or repair equipment, it is said to be in an outage. It is also said to be unavailable, since it is not available (not able) to generate electricity.

Typically, when a coal unit is operating, it will operate for much of the time at full power but will also operate for some of the time at less than full power. Operation at reduced power is due to deratings and, more importantly, to power reductions when demand for electricity is low, especially at night. The output factor for a unit is the ratio of the amount of power the unit actually generated to the amount it could have generated had it always operated at full power whenever it operated at all.

Each unit has a capability, also known as a rated output. This is the maximum amount of electricity the unit can generate on a day-to-day basis when all equipment is working properly. The capability of a unit changes as the temperatures of the air that is drawn into the boiler and of the water that is used to cool the condenser change with the seasons.

Sometimes, a unit is available but has some equipment problem that limits its output to less than its capability – that is, to less than full power. If a unit is limited to less than its capability, it is said to be derated or in a derating.

Some coal units are always, or almost always, operated whenever they are available. This is referred to as being base-loaded. Some base-loaded coal units always operate at the maximum output of which they are capable. Many others are sometimes operated at outputs lower than their capability, because there is not a need for all the power the unit could produce. A common situation is that a unit is operated at maximum capability during the day, when the use of electricity by consumers is highest, but may be operated at reduced output at night, when use of

electricity by customers is lowest. When a unit operates at an output lower than what it is capable of, this is referred to as load following or economic dispatch.

OUTAGES AND DERATINGS

Outages at a generating unit are broadly classified as planned or unplanned. It has been traditional in the utility industry to shut down each unit for a planned outage once each year. The schedule of a planned outage and the work to be done during the outage are planned months or, in the case of major work, years in advance. Outages are usually scheduled for the spring or fall when customers' demand for electricity is relatively low. During a planned outage, work is usually done on many parts of the unit. Traditionally, a coal unit would have a planned outage of a few weeks each year, where the major work would be inspection and overhaul of the boiler. Every fifth year, the planned outage would be longer (typically about 6 weeks). During these longer outages, major overhaul work would be done on the turbine-generator, in addition to the usual boiler work. In the 1970s, large coal units were averaging about 39 days per year for planned outages.[65] By the late 1990s, this had decreased to about 28 days per year.[66] The decrease in outage time was due to a combination of shorter outages and fewer outages, that is, more time between outages. When a unit has major equipment problems, it is often necessary to have a planned outage every year so that the equipment can be inspected and repaired. Thus, replacement of any major problem components (usually with improved designs) is often a requirement for increasing the time between planned outages.

Between planned outages, a coal unit is expected to be available (capable of running) most of the time. As a unit operates, individual components sometimes fail and some of these failures make it necessary to shut down before the next planned outage. Such a situation is referred to as an unplanned outage. Generally, the unit cannot be restarted until the failed component is repaired. During an unplanned outage, repair efforts are focused on the problem that caused the outage. To the extent that manpower and time are available, other equipment may be repaired, but work is generally limited to what can be done within the time it takes to repair the problem that caused the outage. Some unplanned outages, such as those caused by failures of instruments or controls, may last less than an hour. Others, such as those caused by a catastrophic failure of a turbine or generator, may last many months. Throughout the industry, the most common cause of unplanned outages is failures (leaks) of boiler tubes. Outages for boiler tube leaks typically last a day to a few days. Unplanned outages are characterized as forced or maintenance. For a maintenance outages, the equipment problem(s) is (are) such that the utility could have delayed the start of the outage until after the following weekend, if this was economically advantageous.

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[65] Nuclear and Large Fossil Unit Operating Experience EPRI NP-1191, September 1979, page 5-71.
[66] Generation Availability Report, 1995-1999 NERC GADS.

For a forced outage, the equipment problem is such that the start of the outage could only be delayed for a shorter time period, or not at all.

The impact of outages on coal unit availability decreased dramatically during the 1980s and 1990s. In the mid-1970s, the largest coal units (those rated 600 to 1300 MW) were shut down an average of 99 days per year for planned and unplanned outages. By the late 1990s, this had decreased to only 48 days per year, so that the units were able to operate for an average of 51 additional days each year. This was a result of improved performance of many different components in the units. For example, in the 1970s, the large coal units shut down an average of 5.6 times per year to repair boiler tube leaks. By the late-1990s, this had decreased to 2.9 times per year, despite the fact that the units were running more and were older. (The average age of all the largest coal units was only a few years in the 1970s, and had increased to 20 years by the late 1990s.)[67] The most important reason for this improvement has been the fact that problem components have been replaced with components of improved design at many units.

As I mentioned earlier, some equipment problems can limit the electric output from a unit to something less than its capability (less than full power). Some common causes of deratings at coal units are problems with the coal pulverizers and with other coal handling equipment. Like outages, deratings reduce the amount of electricity a unit is available to generate. Consider a unit that has a capability of 500 MW. For ten hours, the maximum output from the unit is limited to 450 MW due to a problem with a pulverizer. We say that the unit was derated by 50 MW (500 minus 450) for 10 hours. The unit was unable to generate 500 MW-hours (50 MW * 10 hours). This is the same as the amount the unit could not generate if it were shut down for one hour (500 MW * 1 hour). We say that the unit lost one equivalent full power hour (EFPH) of EAF (possible generation) as a result of the pulverizer problem.

MEASURES OF OPERATING UNIT PERFORMANCE

For the issues in this case, the most important aspects of the performance of a coal unit are:

- how much electricity could the unit have generated; and
- how much did it actually generate?

As described in the preceding, the availability of a unit to generate electricity is sometimes limited by outages and/or deratings to overhaul or repair components. Even when a unit is available to generate power, the utility may choose to not run it or to run it at less output than it is capable of at the moment. Typically, this would occur at times when the use of electricity by customers is less and when other units are available to generate electricity at a lower cost.

[67] Data for the 1970s are from Nuclear and Large Fossil Unit Operating Experience EPRI NP-1191, 9/79; Data for the 1990s are from Generation Availability Report - 1995-1999, NERC GADS.

Actual Production of Electricity. The standard measure of actual electricity production during a time period is called capacity factor (CF). It is calculated as the actual generation for the time period, divided by maximum possible generation (what the unit could have produced had it run continuously at full power). Consider a unit that has a capability to generate about 700 megawatts of electricity. If that unit ran perfectly for a year (8760 hours), it would produce 700 * 8760 = 6,132,000 megawatt-hours. This is the maximum possible output for the year. If the unit actually produced that much output, we would say that it had a capacity factor (CF) of 100%. If the unit produced 75% of the maximum possible output (.75 * 6,132,000 = 4,599,000 megawatt-hours), we would say that it had a CF for the year of 75%. There are many ways a unit could achieve a CF of 75%. For example it could run at full power (700 megawatts) for 75% of the hours (.75 * 8760 = 6570 hours) and be shut down the rest of the time. Then its output would be 6570 * 700 = 4,599,000. Or, the unit could run for all 8760 hours in the year at 75% of full power (.75 * 700 = 525 megawatts). The output would be 525 * 8760, which again is 4,599,000 megawatt-hours.

Possible Generation of Electricity. There are two measures that give an indication how much a unit could have generated if asked: the availability factor (AF) and the equivalent availability factor (EAF). AF measures the percentage of the time that a unit was able to generate electricity. It does not take any account of whether the unit was able to generate at full power or was limited to some lower output. An AF of 70% would mean that the unit had, in theory at least, been available to operate at some power level for 70% of the time. EAF is a more complete measure of what a unit could in theory have done, since it also takes account of any limitations on the power level at which a unit could have operated. The following simplified example illustrates the calculation of AF and EAF. A hypothetical unit was shut down for equipment repairs or maintenance for 2,190 hours in a year. There are 8,760 hours in a year. We would say that the unit was unavailable 25% of the time (2190/8760 = .25). Therefore, the unit was available to generate electricity 75% of the year: it had an AF of 75%. During the time it was available, the unit was limited (derated) to 80% of full power for 1,000 hours. The unit could not have generated 20% of its rated output for 1,000 hours. This has the same effect as (is equivalent to) being shut down for 200 hours. Therefore, we say that the unit lost 200 Equivalent Full Power Hours (EFPH) due to the derating. Therefore, we say that the unit was unavailable for 2,390 EFPH (2,190 due to outages and 200 due to deratings).[68] We also say that the unit had EAF losses of 2,390 EFPH for the year. The EAF for the unit was 72.72% (100 * (1 – (2390 / 8760)). Note that EAF cannot be measured directly. It is calculated by starting with 100% and then subtracting out all the EAF losses (EFPH that could not have been generated) as a result of each outage and derating that occurred during the time period.

[68] One hour of outage is a loss of one EFPH.

The EAF and CF for units within the industry followed the same pattern as industry outage experience: the amount of outage time decreased as the years passed, so EAFs and CFs increased. In the 1970s the average reported EAF of larger coal units was very poor (around 65%). Through the 1980s and 1990s, the average reported EAF for large coal units improved steadily. By the late 1990s (1995-1999), the average EAF was about 85%. The actual improvement in achievable CF was considerably greater than the 20 percentage points implicit in the preceding. The reason for this is simple. In the 1970s and 1980s, coal units spent a relatively large fraction of the time in reserve shutdown. Thus, the calculated EAFs exceeded the achievable CFs by a considerable amount. (See preceding section.) By the late 1990s, coal units were spending a smaller fraction of the time in reserve shutdown, so the amount by which calculated EAFs exceeded the achievable CFs decreased. In the late 1990s, capacity factors for all large coal units averaged about 70%.[69]

The utility industry has collected data on the performance of generating units for decades. Initially, the data were collected by the Edison Electric Institute, an industry lobbying organization. Data collection was taken over by the North American Electric Reliability Council (NERC) in the late 1970s. Starting with 1982, NERC has collected generating unit operating data in a format called Generating Availability Data System (GADS). While reporting to GADS is voluntary, data are reported for most coal units in the United States and Canada, including the DTE units. There are three types of GADS data:

1. design;
2. performance; and
3. event.

GADS Design (Pedigree) Data comprise basic information on the design of a unit, including the size of the unit, the type of boiler, the boiler manufacturer, the kind of fuel burned, etc. Generally, these data are reported only once in the life of a unit. In a rare situation when the design of a unit is sufficiently changed, the design data would be changed accordingly. Performance data for each unit are reported on a monthly or quarterly basis. The data give basic information about the overall performance of the unit including:

- the capability of the unit;
- how long the unit ran;
- how often it started up;
- how much electricity it generated;
- how much fuel it burned; and
- the basic characteristics of the fuel burned.

[69] Nuclear and Large Fossil Unit Operating Experience, EPRI NP-1191, 9/79; and Generation Availability Report, 1995-1999, NERC GADS.

For any unit, GADS event data are reported for each event (outage, reserve shutdown, or derating).[70] For each event, the data include:

- the type of event (e. g., forced outage, maintenance outage, planned outage, derating, reserve shutdown);
- the dates and times the event started and ended;
- the power output to which the unit was limited (this is zero for outages and reserve shutdowns and some non-zero value for deratings); and
- the cause of the event (this is described by a code that is chosen from a list of codes that correspond to various parts of a unit and problems affecting those parts, and by a brief narrative).

For my analyses, event data were particularly important. These data tell how much of the potential output of electricity from a unit could not be generated as a result of any particular component in the unit.

[70] There is also an event type called "non-curtailing", which is not relevant to my analyses.

KOPPE DECLARATION

APPENDIX C:

FIGURES 1-4

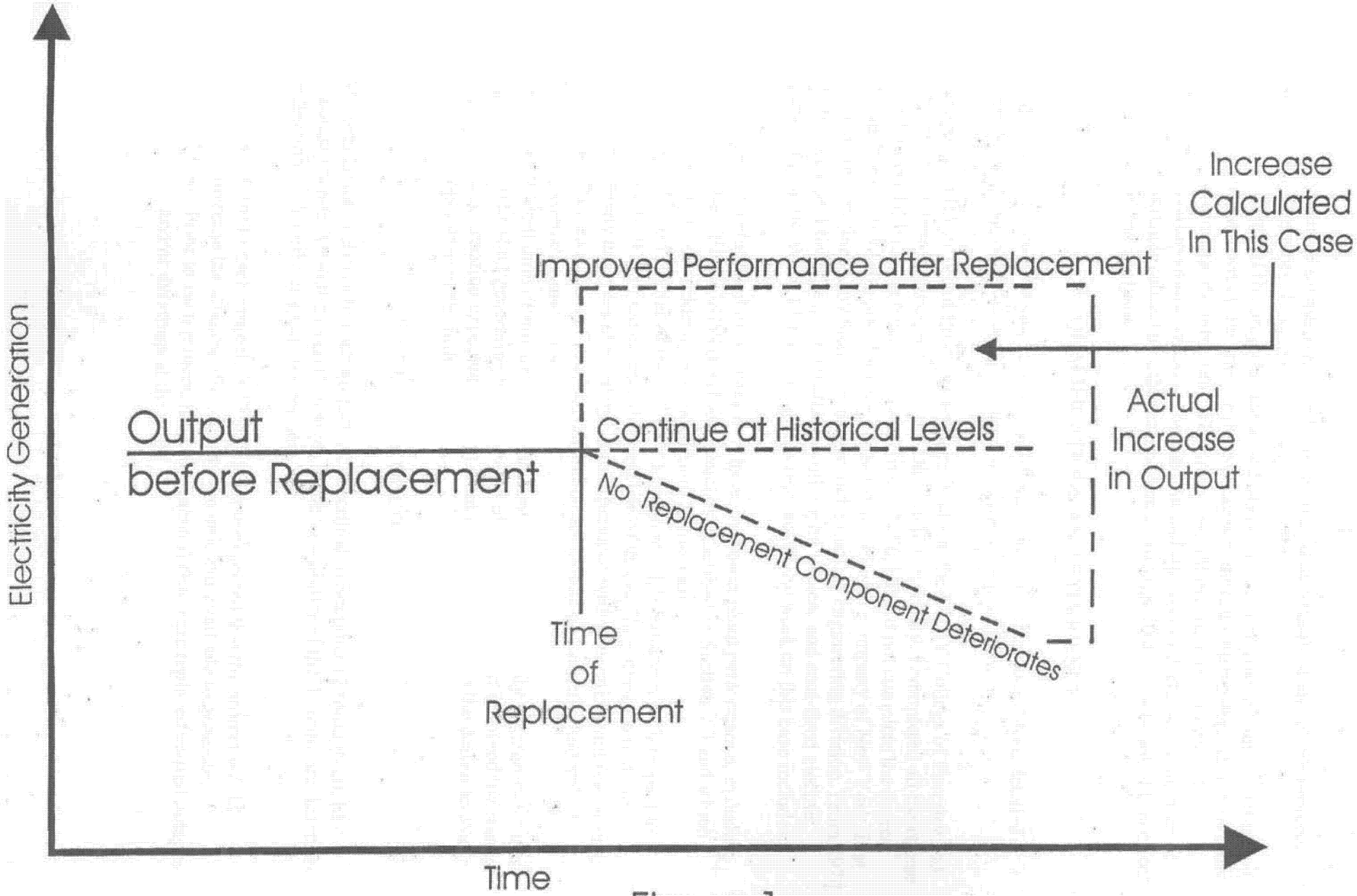
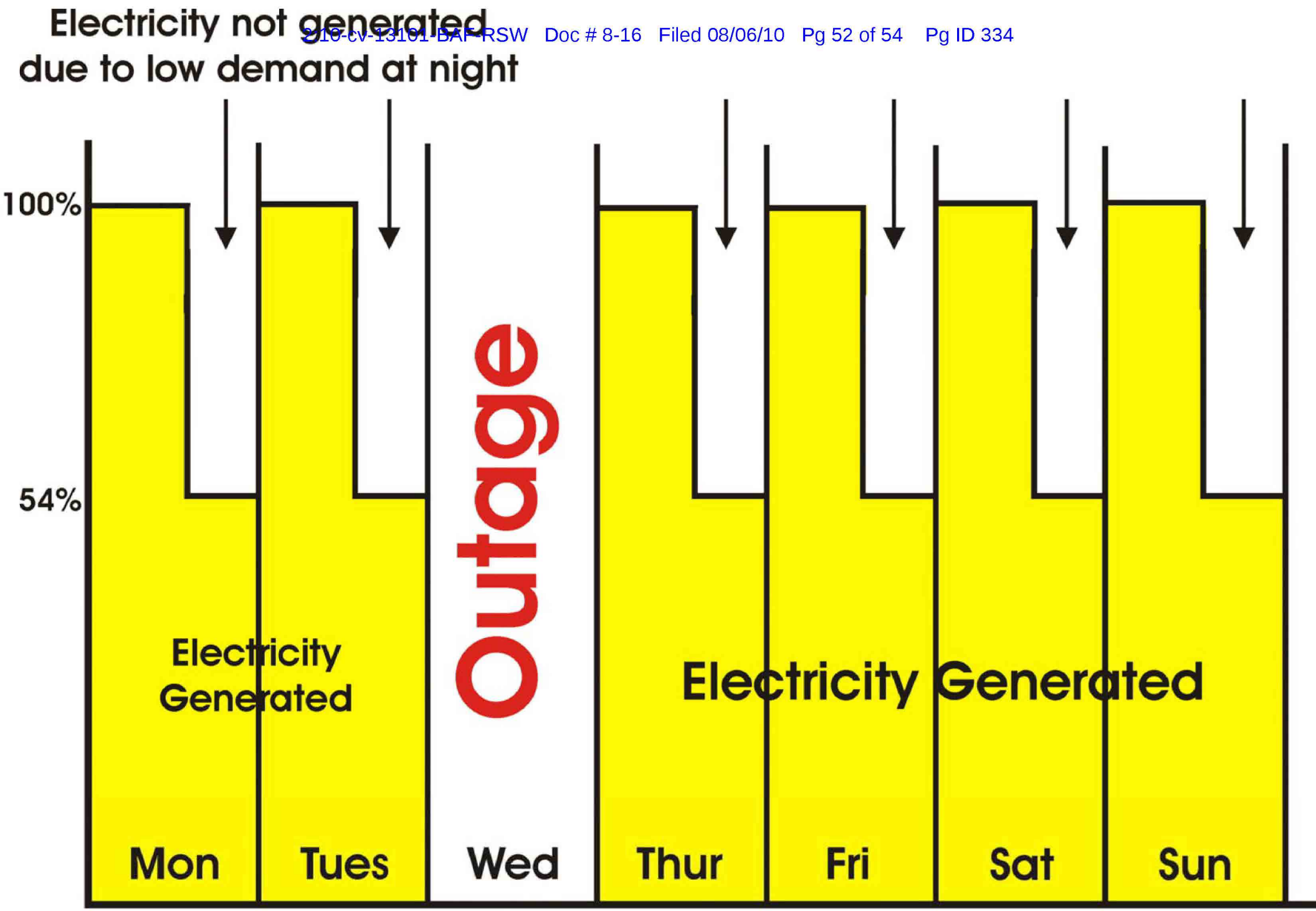
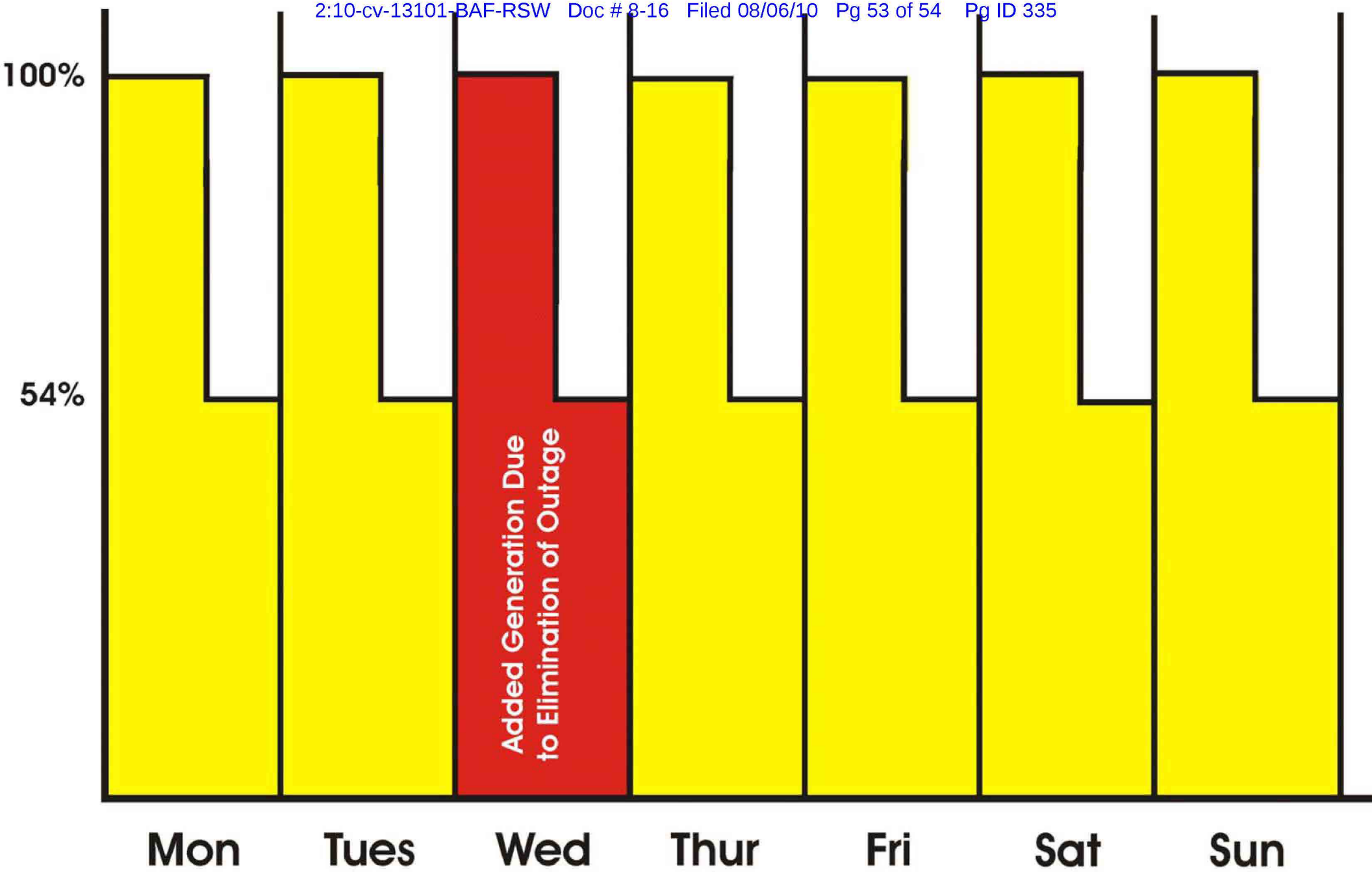


Figure 1

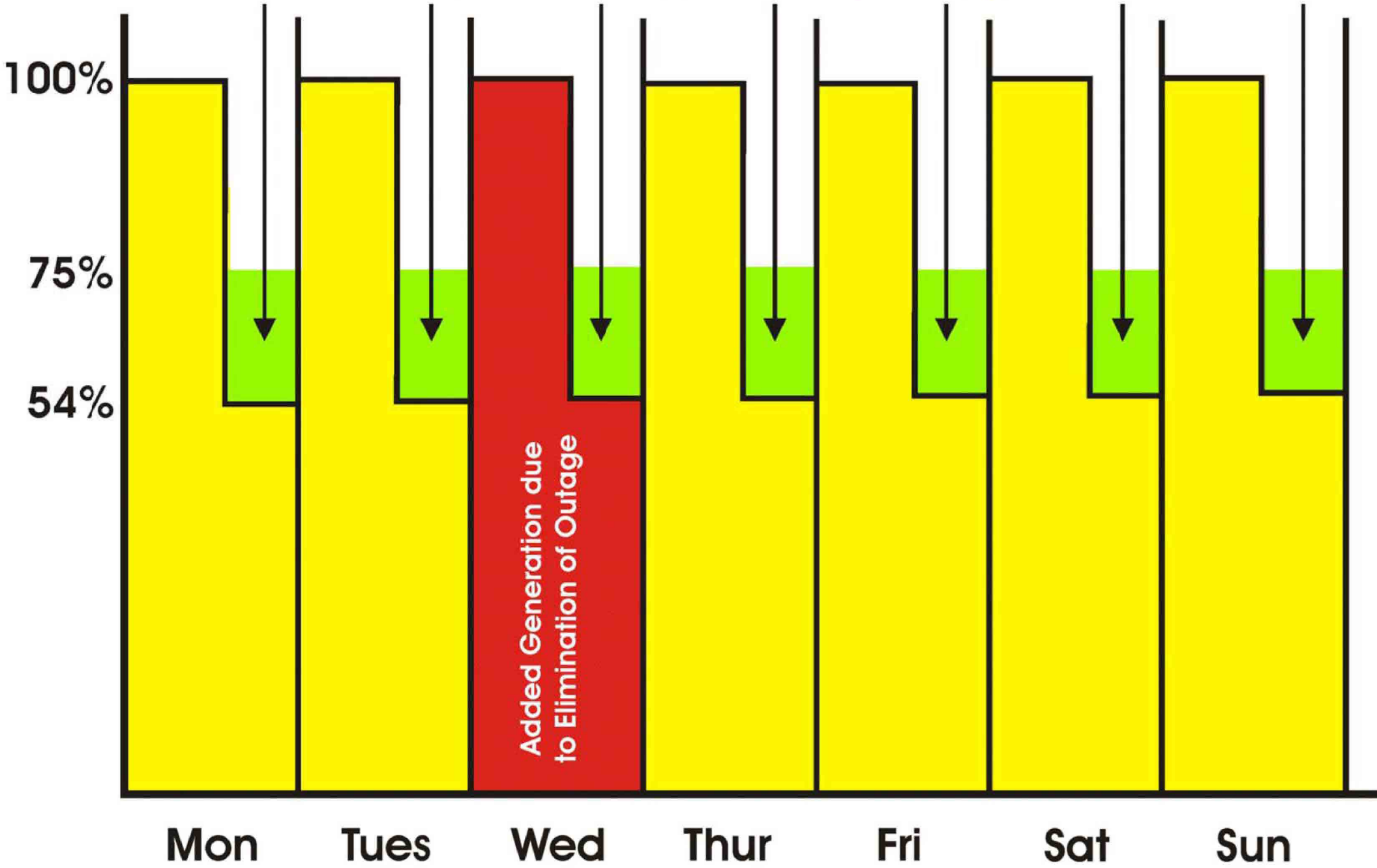
Calculation of Effect of Component Replacement on Generation of Electricity



Idealized week with a one-day outage



Idealized week showing additional Generation if one-day Outage Eliminated



Idealized Week Showing Additional Generation if one-day Outage Eliminated and Demand Increases

Exhibit 6

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	)	
	)	
	)	
Plaintiff,	)	Civil Action No.
	)	
v.	)	
	)	
DTE ENERGY COMPANY, and	)	
DETROIT EDISON COMPANY	)	
	)	
	)	
Defendants.	)	
	)	

DECLARATION OF ALAN MICHAEL HEKKING

I, Alan Michael Hekking, declare as follows:

1. This Declaration is informed by my 21-½ years of personal knowledge and experience gained while working for the Tennessee Valley Authority (TVA) in various engineering and management positions at its coal burning power plants and in the central office, and by knowledge gained through my involvement in the EPA utility enforcement initiative of which this litigation is a part. My experience is detailed below and in my attached resume. I am at least 18 years of age and competent to testify to the matters contained herein.

My Background and Experience

2. In more than two decades at TVA, I worked at a number of coal-fired power plants in positions including Mechanical Maintenance Supervisor, Assistant Plant Manager, and finally Plant Manager.

3. I was involved in major capital improvement projects including boiler component replacement projects. Components replaced include burners and cyclones, boiler floors and walls, economizers, primary and secondary superheaters, and reheaters. My involvement included project scope development, project authorization, detailed planning and implementation, budgeting and control of expenditures, and evaluation of results.

4. In 1994 I took a position as the supervisor of a local air pollution control program in Memphis, Tennessee. I supervised a group of engineers performing permitting, new source review, compliance monitoring, and enforcement activities. I remained in that position for approximately seven years. In 1997, while working in this position, I became involved with the U.S. EPA utility enforcement initiative, performing compliance inspections at coal fired power plants in EPA Regions 3, 4 and 5.

5. I began working as a consultant for the Department of Justice in 2000, serving as a utility expert. I provided the expert testimony on the subject of routine maintenance in the Tennessee Valley Authority case (heard by the Environmental Appeals Board) in the summer of 2000. I also provided expert testimony on the subject of routine maintenance in *United States v. Ohio Edison Company, et al.* (S.D. Ohio), *United States v. AEP, et al.* (S.D. Ohio), in *United*

States v. Illinois Power Company, et al. (S.D. Ill.), and in *United States v. Cinergy* (S.D. Ind.). I have and still am working on other cases in the utility enforcement initiative. I am being compensated for my work in this case at a rate of $90 per hour (with higher rates for field work and testimony).

The Power Plant and the Major Components of the Boiler

6. Power plants generate electricity using three major components: the boiler, turbine, and generator. A boiler is a large building-like structure 6-12 stories high in which coal is burned and the energy (heat) from the combustion process is transferred to water to produce steam. Water and steam are carried through the boiler by thousands of tubes. The tubes not only form the structural walls of the boilers, but many boiler components are actually assemblies of tubes that hang inside the boiler suspended from the roof and walls.

7. The inside of the boiler is the area where the fuel is burned to produce heat. Water circulating inside the wall tubes absorbs the heat and turns to steam. The steam then circulates through the tube assemblies suspended inside the boiler before it leaves the boiler to generate electricity in the turbine and generator.

8. Fossil fuel-fired steam-electric generating facilities provide electricity through a process that is designed to release the chemical energy of the fuel, convert it to heat energy, mechanical energy and finally electrical energy. The boiler receives the fuel, converts the chemical energy stored in the fuel through combustion, also known as burning or oxidation, and applies the heat energy released by the combustion to convert water in the boiler tubes into steam. The steam is then supplied to the turbine where the heat energy of the steam is converted to mechanical energy in the form of a rotating shaft. The rotating shaft is connected to and turns the generator to produce electricity.

9. The gross unit operating capacity is generally regarded as the output of the generator as described on the nameplate. The nominal rating is the output of the generator under the maximum boiler output conditions; pounds per hour steam flow at a given temperature and pressure. A generating unit can be operated at more or less output than the gross capacity depending upon equipment condition. Therefore, actual generating capacity would be the gross capacity adjusted for equipment conditions.

10. Boilers are composed of two major sections – the radiant section and the convection section. The radiant section includes the furnace, where combustion occurs, and the upper sections of the boiler exposed to the radiant energy. The wall tubes, also called water wall tubes, or furnace wall tubes absorb radiant energy. The secondary superheaters and secondary reheaters (when they are employed) are large bundles of tubes hanging or placed into the upper region of the radiant section of the boiler and absorb radiant energy to heat the steam traveling inside the tubes.

11. The convection section of the boiler is designed to recover the heat energy of the gases through a heat transfer process called convection. The convection section receives the hot combustion gases that have traveled up through the radiant section as the gases turn horizontally and then down towards the boiler exit. In the boiler convection sections, the flue gas flows through the primary superheater, then the primary reheater, and finally the economizer to absorb the heat contained in the flue gas and transfer the heat to the water or steam passing within the tubes. Typical flue gas temperatures are 2,500° F entering the superheater, 1,700° F entering the reheater, 1,000° F entering the economizer, and 750° F leaving the economizer.

12. After the flue gases pass through the economizer and leave the boiler, they still contain a significant amount of heat. The gases at this point can have temperatures as high as 800° F. Air heaters, also know as air pre-heaters, are heat exchangers that recover heat from the exiting flue gas and transfer it to the incoming combustion air leaving the FD fans, prior to entering the windbox. Subsequently, the flue gases, after leaving the air preheater, enter the air pollution control devices for removal of pollutants.

Boiler Water and Steam Cycle

13. The water and steam cycle is a closed-loop process that involves not only the boiler but also several other components. The water and steam cycle begins with feedwater. The feedwater is pumped by the boiler feed pumps to the boiler and is distributed to the boiler wall tubes. Next, the water absorbs the heat released from coal combustion as it flows through the tube walls. The water changes to steam and receives additional heat as it travels through the suspended tube assemblies before leaving the boiler. The steam is then supplied to the turbine where it releases most of the heat energy transferred from the boiler. The steam is converted back to water in the condenser upon leaving the turbine. The water, as condensate, is pumped via a boiler feed pump back to the economizer in the boiler.

14. The water and steam that flow through the tubes of the boiler components control tube metal temperature by removing heat and carrying it from the wall tubes. If this heat transfer did not occur, the tubes would be destroyed almost immediately by the intense heat from the coal combustion. Long-term exposure of the tubes to the temperatures in the boiler leads to tube cracks and leaks even when effective cooling by steam and water occurs. Boiler tubes are periodically sampled and evaluated using metallurgical analysis techniques to determine their status regarding long-term degradation.

15. Each of the main components of the cycle -- the boiler, turbine, condenser, and boiler feed pump are discussed below with emphasis on the boiler water and steam components.

a. Economizer. Feedwater is pumped by the boiler feed pump to the economizer. The economizer is the last component that receives heat energy from the combustion gas and is located in the lowest portion of the convection section of the boiler. The purpose of the economizer is to absorb as much of the heat remaining in the flue gases as possible before the gases exit the boiler. The feedwater enters the economizer inlet header, which distributes the feedwater to the economizer tubes. The economizer tubes are looped back and forth horizontally across the direction of the gas stream.

b. Steam Drum and Waterwalls. Feedwater exits the economizer and enters the main steam drum. The main steam drum is a very large tube or cylinder – some main steam drums are almost four feet in diameter. The steam drum length spans the full width of the boiler. The steam drum is designed to distribute the feedwater to the boiler water wall tubes and receive the steam that rises up from the tubes after heating. Downcomers transport the feedwater from the steam drum to the lower waterwall headers that distribute the feedwater to the furnace wall tubes inside the boiler. These tubes carry water to be converted to steam absorbing the radiant energy released by combustion. The steam then rises in the tubes and is returned to the steam drum. The steam and water are segregated within the drum. The steam leaving the drum passes through steam-water separators to remove any remaining water from the steam, and the water is returned to the downcomers.

c. Superheater. The superheater is used to increase the energy content of the

steam, thereby raising the energy state to super-saturation. Superheaters are often comprised of two sections – the primary superheater and the secondary superheater. The primary superheater is an assembly of tubes located at the top of the convection section upstream (in the direction of flue gas flow) of the economizer (this area is also called the heat recovery area of the boiler). Primary superheater construction appears similar to the economizer shape and orientation, but the tube material is selected to withstand the higher gas and steam temperatures than those experienced in economizers.

The steam from the drum first enters the primary superheater inlet header, which distributes it to the individual tubes. The inlet header is a large cylindrical tube or pipe usually one to two feet in diameter. The header is connected to the inlet of each primary superheater tube element and is therefore as long as the primary superheater is wide. The steam flows through the tube elements reversing direction several times as the tubes turn 180° back and forth across the gas flow. The steam exits the tube elements to the outlet header. The outlet header is similar in design to the inlet header and collects the steam for transfer to the secondary superheater.[1]

After partial superheating in the primary (first) superheater, the steam is directed to the secondary superheater. Secondary superheaters are located in the upper region of the radiant section of the boiler where the gas temperature is high and radiant energy is available for absorption. The steam leaving a secondary superheater usually has a temperature of approximately 1,000°F and attains the highest energy level of the steam cycle. The steam is then sent to the inlet of the high pressure (HP) turbine.

d. Reheater. The steam leaving the HP turbine is directed to the reheater section of the boiler. Reheaters consist of inlet and outlet headers connected by assemblies of tubes suspended in the flue gas flow to absorb heat energy. Reheaters recover additional heat energy from the flue gas to increase the energy state of the steam in order to reduce water formation in the turbine. In some boilers, two reheaters are employed, a primary heater and a high temperature reheater.

e. Boiler Tube Life. Conditions inside of an operating boiler can affect the life of boiler tubes. The four predominate impacts on tube life are thermal cycling (heating up and cooling down), external corrosion from exposure to caustic agents, erosion from the high flue gas velocities and entrained ash particles, and internal corrosion caused by poor water quality. During idle periods it is customary to blanket the boiler with inert nitrogen to minimize corrosion. Tube leaks resulting from these different failure mechanisms are the overwhelming reason for the replacement of boiler components described in this declaration.

Power Plant Maintenance

16. In a coal burning power plant, the maintenance group is responsible for the day-to-day maintenance of the various pieces of installed equipment as well as the structures and physical property. It is also responsible for the planning and execution of the maintenance activities that are performed during planned and unplanned periodic unit shutdowns. The group consists of supervision and management, engineering and technical support, and a wide variety

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[1] The term "element" is used frequently to describe sets of economizer, reheater or superheater tubes fabricated into specific sizes and shapes. A complete set of elements constitutes an economizer, reheater or superheater section.

of skilled and semi-skilled craftsmen.

17. In a power plant, maintenance activities can be subdivided into three broad skill groupings: mechanical, electrical and instrumental. The maintenance staff consists of mechanics with skills in each of the above skill groupings. Typically, the mechanical group has the majority of the craftsmen possessing the skills of welding, metal fabrication, machine shop metal working, carpentry, piping systems and valve repair, and machinery disassembly, inspection, repair and reassembly. It is responsible for the repair of mechanical equipment and systems such as boilers, turbine-generators, pumps, compressors, fans, pulverizers, and piping systems. Contractors are used extensively to supplement the maintenance workforce particularly during scheduled annual outages.

18. The life and reliability of power plant equipment is directly related to the design of the equipment, proper operation, and the type and amount of maintenance performed. Proper operation includes use of the equipment for its designed purpose and operation within designed operating parameters. Maintenance includes preventative activities such as regular lubrication changes, use of diagnostic tools, and other regularly scheduled activities as the service and the manufacturer recommends.[2]

19. On a day-to-day basis, the maintenance crews respond to maintenance job orders from operations personnel as breakdowns and equipment problems develop. There can be many job orders generated during the course of a 24-hour day.

20. Power plant maintenance can be characterized as preventive, predictive, and reactive (or corrective). Preventive maintenance are those repetitive tasks that are performed on a regular schedule of either elapsed time or hours of operation, much like changing the oil in your car every 3,000 miles. One could further define preventative maintenance as maintenance recommended by the equipment manufacturer at given intervals to insure proper operation of the equipment. Intervals are typically defined as being equipment-specific, days, months, or based upon operating hours. Predictive maintenance is where one monitors the performance of a piece of equipment, observing for trends, and performs maintenance in response to the results of equipment monitoring, such as lubrication oil analysis and vibration. Thus, monitoring indicates that a failure will occur in the future and repairs will be made to prevent the failure. In contrast, one could describe reactive maintenance as "fix it after it breaks."

21. In general, maintenance work in a power plant can also be divided into three categories: running maintenance, forced outage maintenance, and planned or scheduled outage maintenance. Running maintenance is performed while the units are in operation. Examples include valve repair, steam and water leak repair, pump repair, pulverizer maintenance, and preventative maintenance. Forced outage maintenance takes place when a generating unit is removed from service by an unplanned event such as a boiler tube leak.

22. During a forced outage, there are a number of routine maintenance activities that take place every time a unit is out of service. The maintenance group will accumulate maintenance job orders that have been initiated that require a unit shutdown to accomplish. Maintenance job orders that can be completed during a forced outage period, taking into

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[2] *See generally*, STEAM - Its Generation and Use, Chapter 44, Babcock & Wilcox (40th edition, 1992); and COMBUSTION - Fossil Power, Chapter 23, Combustion Engineering (4th edition, 1991).

consideration the anticipated return to service date and the available resources, will be scheduled for work during the downtime. Boiler tube leaks are the predominant cause of forced outages, so a leak test is conducted to locate any tube leaks present.

23. Scheduled outage maintenance occurs when a generating unit is removed from service to perform maintenance tasks that cannot be performed during periods when the unit is in operation or during short forced outages. Generally, although the frequency may vary somewhat, utilities plan scheduled outage maintenance at each unit every 12 to 18 months. These outages are scheduled in the spring and fall when the demand for electricity is minimal and are typically two to four weeks in duration. The maintenance staff at the plant keep an active list of activities planned for execution during each scheduled outage (unless they had been completed during a previous forced outage).

24. Routine boiler maintenance activities that are performed during scheduled annual outages include the following:[3]

- Cleaning of boiler and related ductwork to facilitate maintenance access and inspections;
- Inspection of the furnace and gas path;
- Inspection including non-destructive examination of known trouble areas;
- Individual tube repair/replacement;
- Inspection of tube shields and high erosion areas;
- Inspection, repair and replacement of refractory in the slag necks and troughs;
- Inspection and repair of ductwork and expansion joints;
- Cleaning and inspection of boiler penthouses;
- Water blasting, inspection, stud replacement and new refractory (cyclone fired boilers);
- Inspection and repair of boiler casings, doors and inspection ports;
- Inspection and repair of gas path deflection baffles and flow distributors;
- Inspection and repair of all dampers (air and gas);
- Remove, disassemble, inspect and repair ignitors;
- Cleaning, inspection and repair of external steam header vestibules;
- Pressure test of water and steam tubing components;

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[3] *See generally*, State-of-the-Art Maintenance and Repair Technology for Fossil Boilers and Related Auxiliaries, EPRI document CS-4840, Project 2504-1, March 1987.

- Chemical cleaning of water-side tubing to remove internal deposits.

In addition to the routine boiler maintenance activities listed above, there are many more activities normally performed each outage on other plant equipment such as heat exchangers, pulverizers, turbines, generators, condensers, fans, pumps, and motors.

25. Boiler tube leaks cause boiler shutdowns (forced outages), sometimes immediately. Boiler tube leaks must be repaired. Hence, they fall into the category of reactive or corrective maintenance. Upper management approval is not required for the initiation of the tube leak repairs unless the work is out-sourced. The use of contractors sometimes requires only the plant manager's approval. The following discussion describes a typical boiler tube leak repair.

26. For a typical tube leak repair, maintenance personnel will begin opening boiler access doors within a few hours after the unit has been removed from service. Maintenance workers must wait for the boiler to cool down. Initial mobilization by the maintenance department involves working with operations to locate the leak, initiate unit shutdown, gain access, and cool down the boiler. After maintenance has identified the number, location, and type of leak(s), operations personnel will drain the boiler. Once the boiler has been drained and the temperature is tolerable for the workers, tools and materials will be moved into the location of the leak to initiate repairs. Typical tools and materials used are scaffolding, lights, welding machines, oxygen-acetylene torches or saws (for cutting tubes, if necessary), and air hoses for operating pneumatic tools. All of these materials can usually be moved into the work area, inside of the boiler, through the access openings provided as original boiler equipment.

27. Types of tube leaks can be categorized as pinholes, cracks, or ruptures. Repair methods can be categorized as weld repair or replacement. It is common for the initial leak to cause damage to surrounding tubes, particularly when the initial leak was small and the unit continued to operate while the leak was present. The additional damage occurs from the release of the high energy fluid impinging upon neighboring tube surfaces.

28. Weld repairs can either be a padweld,[4] in the case of a pinhole, or a grind out and weld repair[5], in the case of a crack. Weld repairs are usually favored over replacement because the amount of time to conduct repairs is generally much shorter. If there is extreme urgency to return the unit to service, weld repairs can be made that serve as a short-term fix, and permanent repairs can be made during the next planned unit outage.

29. When the damage to the tube is beyond weld repair, replacement becomes necessary. Replacement of the damaged tube can involve a short section of the tube, called a dutchman, or a longer length that can include elbows. The amount of material replaced is dependent upon the extent of the damage to the tube, the location, and access considerations.

30. When repairs have been completed, maintenance will notify operations personnel. Operations will fill the boiler with water and start a boiler feed pump to pressurize the boiler for

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[4] The term padwelding means repairing a tube leak by placing weld material on the location of the leak to seal the hole and build up the wall thickness.

[5] In the grind out and weld repair process, a rotary grinder is employed to remove the metal around the crack. After the cracked metal is removed, a weld is made to fill the void.

a hydrostatic test. Maintenance personnel will check the repairs for integrity and recheck the rest of the boiler for additional leaks. After it has been determined that no leaks exist, maintenance personnel will remove all of their tools and materials and close the access doors. Operations will establish a coal fire in the boiler in preparation to return the unit to service.

31. In my experience, the majority of tube leaks are repaired within 48 hours or less, and are performed by as few as 2 - 3 workers.

Detroit Edison's Monroe Power Plant

32. The Monroe Power Plant is located in Monroe, Michigan, on the western shore of Lake Erie and consists of four coal-fired steam electric generating units with more than 3,100 MW of rated capacity. The plant is the third largest coal-fired plant in North America. In 2006, the plant emitted 103,520 tons of sulfur dioxide and 31,809 tons of nitrogen oxides. The Monroe Plant is in an area classified as non-attainment for ozone and $PM_{2.5}$. EPA Inspection Report of Monroe Generating Station, June 3, 2010.

33. Monroe Unit 2 began operation in 1974. Gross electrical generation of Monroe Unit 2 is 823 MW with a net capacity of 795 MW. The Unit 2 boiler was manufactured by Babcock & Wilcox, and Detroit Edison reported that heat rate is 7624 mmBTU/hr. EPA Inspection Report, June 3, 2010.

34. In testimony before the Michigan Public Service Commission, Paul Fessler, Vice President of Fossil Generation for the Detroit Edison Company, explained the need for spending significant amounts of Fossil Generation capital, operation and maintenance (O&M), and fuel handling expenditures in order to improve plant availability levels. In the matter of the Application of the Detroit Edison Company, Case No. U-15768, PF-4 (Fessler Testimony).

35. Mr. Fessler explained that: "As generating plants age, they require significant maintenance resources to keep them operating in an optimal and reliable condition. Detroit Edison has experienced, and continues to experience, operational reliability issues on major system components that need to be addressed through on-going O&M and capital investments." Fessler Testimony, PF-1,-9.

36. Mr. Fessler further explained that a "formal Boiler Tube Failure Reduction team" had been formed to study and evaluate boiler components that caused unplanned outages within the fossil fleet in order to improve unit availability and reduce maintenance costs. Fessler Testimony, PF-13. "Detroit Edison has invested significant capital and maintenance dollars over the last several years to maintain and improve generation unit availability, reduce overall plant costs. . . ." Fessler Testimony, PF-14.

The Monroe Unit 2 Rehabilitation

37. On April 22, 2010, *The Monroe Evening News*, a newspaper of general circulation in Monroe, Michigan, where the Monroe Power Plant is located, published the following story as the front page, lead article:

Extreme Makeover: Power Plant Edition
By Charles Slat
ctslat@monroenews.com

DTE Energy is in the midst of one of the largest maintenance shutdowns in the history of its Monroe Power Plant, a project that will last about 83 days, employ more than 600 construction workers and pump about $65 million into the economy.

The project has involved cutting a giant access hole near the top of the 12-story power plant to remove some parts of the massive boilers that have been in place since the generating station began operating nearly 40 years ago. "We've been planning this for 10 months," said Chris Denunzio of Monroe, a project leader with URS, a San Francisco-based engineering and construction firm that's coordinating the work.

The coal-burning plant has four boiler/turbine-generator units, each capable of generating about 800 megawatts of electricity. Each massive multi-story boiler is lined with thousands of tubes that carry water, which is converted to steam by the fire in the boiler and then used to spin turbines connected to an electrical generator.

Focused on the Unit 2 boiler, the scope of the work includes removing large sections of the tubing that has corroded or weakened over time and replacing them with new tubing. About 2,000 square feet of tubing or "water wall" sections are being replaced.

Replacement of the "economizer", a massive array of tubed sections that act much like a radiator and increase boiler efficiency, also is part of the job. About 642 of the sections are being installed to create an 80-foot wide array. The heavy 36-foot long sections are hoisted from the ground by giant crane to a hole that was cut into the side of the plant to provide access. They then are loaded onto a crane monorail specifically built for the work inside the plant to carry them to the location where they are being installed. More than 500 lifts by crane will be needed to carry out the maintenance project, DTE officials said.

Large sections of piping in the reheater pendants of the boiler also are being replaced. It's the first time that the plant has replaced economizer and reheater components at the same time.[6]

Each new part and new weld is inspected or checked using X-ray scanning that will reveal structural or welding flaws much in the manner a medical X-ray will show a bone fracture. "If we find something even the size of a speck of pepper, we have to grind that out," Mr. Denunzio said.

He said the outage overall is a "large, labor-intensive job."

Crews are working in two 10-hour shifts, six days a week to get the job done. Mr. Denunzio said an effort is made to use mainly local unionized workers, including boilermakers, pipefitters, carpenters and laborers. Labor costs represent more than $40

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[6] Detroit Edison spent $15.4 million for replacement of the Monroe Unit 2 high temperature reheater and $14.5 million to replace the economizer on Monroe Unit 2. Fessler Testimony, PF-26.

> million of the project. About 100 Detroit Edison skilled-trades employees also are involved in the work.
>
> Mr. Denunzio said an effort also is being made to team younger trade workers with seasoned veterans to provide a learning opportunity for the younger ones.
>
> Part of the work also involves installing a new nine-ton exciter, a device that provides voltage to create the electromagnetic field needed for the generator rotor to produce electricity. The rotor itself has been removed and sent out to be rewound.
>
> Boiler feedwater pumps are also being refurbished and hundreds of other parts are being replaced, reworked or serviced. The outage includes about 2,700 individual work projects.
>
> The bottom line is that the plant boiler unit will run far more efficiently and have an extended life, officials said.
>
> Similar work is being planned in the years ahead for other boilers at the plant, which continue to operate while the project is underway. The project began March 13 and might be completed by the first week of June.
>
> Meanwhile, the plant also continues to be the focus of other unrelated work that is adding costly equipment to further reduce its emissions.

Charles Slat, "Extreme Makeover," *The Monroe Evening News*, p. 1A, 11A, April 22, 2010.

<u>The Monroe Unit 2 Rehabilitation Was Not Routine Maintenance, Repair or Replacement</u>

38. Monroe Unit 2 was nearing the end of a normal operating life of 30 to 40 years. After 36 years of operation, Detroit Edison determined that a number of major components of the unit required replacement. The economizer was causing increased forced outages caused by misaligned tubes and pluggage in the backpass. At the time of its replacement, approximately 10% of all economizer tubes had been plugged (i.e., taken out of service). EPA Inspection Report, June 3, 2010. The reason for the reheater replacement was because of increased forced outages in the reheater related to creep failure. *Id.* As indicated above, these major components included 2,000 square feet of waterwall sections, the economizer, the high temperature reheater, boiler feedwater pumps, the exciter, generator lead box, a dozen burner lines, partial replacement of the coal silos and "hundreds of other parts [which were] replaced, reworked or serviced." *Monroe Evening News,* p. 11A; EPA Inspection Report, June 3 2010. This $65 million project was clearly part of a plan to extend the operating life of this unit. Massive boiler rehabilitation projects to extend the life of a unit are beyond the scope of routine maintenance, repair and replacement activities.

39. Based on my experience as a plant manager at TVA, and my experience as an expert over the past decade, projects of this type are performed to reduce forced outages, to improve availability levels at the plant, and to reduce maintenance costs and maintenance outages. In my experience, the only way that an electric utility can "pay for" $65 million in rehabilitation work is to generate more electricity afterwards and to sell more electricity. Thus, major boiler work such as at the Monroe plant has a pay back period and the capital costs are viewed as an investment with an expected return. Mr. Fessler confirmed in his testimony before the Michigan Public Service Commission that Detroit Edison spent significant amounts of money in order to

improve plant availability levels by reducing forced outages, as well as to reduce maintenance costs, to include the unit rehabilitation work at Monroe Unit 2.

40. The rehabilitation project at Monroe Unit 2 is a massive project that was clearly beyond the capability of the maintenance staff at the Monroe plant. The project leader for the San Francisco-based engineering and construction firm that is coordinating construction said that planning had been ongoing for 10 months. The job has taken three months, involves 700 construction workers, and involves cutting a "giant access hold near the top of the 12-story power plant to remove some parts of the massive boilers (sic) that have been in place since the generating station began operating nearly 40 years ago." *Monroe Evening News,* p. 1A; EPA Inspection Report, June 3, 2010. The scope of the work includes "removing large sections of the tubing that has corroded or weakened over time and replacing them. . . ." These include 2,000 square feet of waterwall sections, the entire economizer, described as a "massive array of tube sections" that comes in heavy 36-foot sections. These massive sections are so heavy that they must be "hoisted from the ground by [a] giant crane to a hole that was cut into the side of the plant to provide access. They then are loaded onto a crane monorail specifically built for the work inside the plant to carry them to the location where they are being installed." *Id.* Detroit Edison officials said that more than 500 crane lifts will be necessary for the boiler rehabilitation. The cost of the economizer replacement alone cost $14.5 million. Fessler Testimony, PF-26. The boiler rehabilitation also includes replacing the entire high temperature reheater at a cost of $15.4 million, which is just downstream of the secondary superheater. The project leader described the boiler rehabilitation as a "large, labor-intensive job." *Monroe Evening News,* p. 11A.

41. The rehabilitation at Monroe Unit 2 is not and was not treated as ordinary or routine maintenance by Detroit Edison. The Monroe maintenance staff kept the boiler operating with routine maintenance for nearly 40 years before the decision was made to perform a $65 million rehabilitation. As Mr. Fessler indicated in his testimony to the Michigan Public Service Commission, Detroit Edison distinguishes between major capital projects designed to improve boiler operation, increase efficiency or availability and/or address operating and maintenance problems related to the boiler and turbine systems (PF-17), and "[n]on-periodic outage activity reflect[ing] standard 'day-to-day' work that is done to maintain plant equipment. This includes inspections, servicing, and minor maintenance that does not require the unit to be taken offline to complete as well as expenses associated with forces outages and derates." Fessler Testimony, PF-30. For example, maintenance expenses that are for standard day-to-day work done to maintain the plant equipment in its current condition are recorded in O&M accounts such as Account 512 "Maintenance of Boilers." Fessler Testimony, PF-32.

42. In contrast, major capital projects are included in the Fossil Generation Plant Improvements Projects (PIP) capital budget which "is approved annually for expenditures during the next calendar year. . . . Requests for capital require initiation of an approved project request that includes a detailed explanation of the project and an initial estimate of cost and benefits." Fessler Testimony, PF-14.

43. This is the first time that the complete economizer and complete high temperature reheater have been replaced in 36 years of operation, and certainly the first time that the Unit 2 boiler has been rehabilitated. EPA Inspection Report, June 3, 2010.

44. The cost of the Monroe Unit 2 rehabilitation is $65 million.

45. Based on the facts described above, it is clear that the massive boiler rehabilitation at

Monroe Unit 2 is not routine maintenance, repair or replacement. The basis for this conclusion is summarized below:

The nature and extent of the rehabilitation was massive, requiring resources clearly beyond the capability of the existing maintenance staff. Major components of the boiler are being replaced including the economizer and the high temperature reheater, which are critical to the function of the boiler. Monroe Unit 2 has been out of service for nearly three months while the unit is being rehabilitated and cannot generate electricity during this time. Based on my experience, the work could not have been carried out by plant maintenance staff, and the materials, equipment and resources necessary to carry out the boiler rehabilitation came from outside the plant. The reheater was supplied by the original equipment manufacture, Babcock & Wilcox, and the economizer was supplied by Doosan Babcock. EPA Inspection Report, June 3, 2010. A unit rehabilitation of this magnitude and complexity could only have been done by outside specialty contractors using hundreds of workers with heavy equipment brought to the job site specifically for this work, and with components specifically designed and engineered for this project.

The purpose of the project was to rehabilitate an aging generating unit that will extend the life of the unit, improve unit availability by reducing forced outages, and reducing maintenance costs and outage time, and as the newspaper article said, to "boost . . . efficiency."

Detroit Edison did not treat the rehabilitation as ordinary or routine. This project was neither accounted for as routine maintenance, nor was it presented to the Michigan Public Service Commission or the public as routine. As characterized by the headline in the Monroe Evening News, it was an "Extreme makeover."

The time necessary for the planning and execution of the rehabilitation greatly exceeded the amount of time necessary for routine maintenance, repairs or replacements.

This was the first and only replacement of major boiler components and the first boiler rehabilitation in nearly 40 years of operation. Based on my experience in the industry and my review of capital projects in other enforcement cases, a rehabilitation of this magnitude, scope and cost is highly unusual in the industry. Of the hundreds of major capital projects I have reviewed, I know of only a handful of rehabilitation projects at coal-fired units that approach this project in cost or that rival this one in nature and extent.

The project was costly in both absolute and relative terms. The unit rehabilitation cost approximately $65 million and at least $30 million of that was charged to a capital account rather than a maintenance account.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Alan Michael Hekking

Executed on July 23, 2010 in Central, South Carolina

Exhibit 7

4.37

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

SEP 9 1988

OFFICE OF
AIR AND RADIATION

MEMORANDUM

SUBJECT: Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to the Wisconsin Electric Power Company (WEPCO) Port Washington Life Extension Project

FROM: Don R. Clay, Acting Assistant Administrator for Air and Radiation (ANR-443)

TO: David A. Kee, Director
Air and Radiation Division, Region V

This is in further response to your March 25, 1988 memorandum requesting guidance on PSD applicability regarding the proposed renovation of the Port Washington Power Plant by the WEPCO. I have also addressed the question whether the renovations proposed for this facility would subject the individual units to Subpart Da of the NSPS.

Based on the information presented in your memorandum, subsequent written information received from WEPCO, information provided by the State of Wisconsin, and other information contained in the Environmental Protection Agency's (EPA's) files on this matter, I have concluded that, as proposed, this renovation project would not come within the PSD and NSPS exclusions for routine maintenance, repair, and replacement, nor the exclusions for increases in production rate or hours of operation. It also appears that the project would increase emissions within the meaning of these two programs. Thus, the renovation project likely would be subject to PSD review as a major modification of an existing stationary source and that the renovations proposed for units 1-5 at this facility probably would subject the individual units to Subpart Da of the NSPS as a modification. However, WEPCO has not yet requested EPA to make an applicability determination. In any case, it would not be possible to make final applicability determinations at this point, for three basic reasons.

First, EPA must be supplied sufficient data regarding the various pollutants emitted by the Port Washington facilities to determine, on a pollutant-specific basis, how the proposed renovations would affect emissions levels. Second, WEPCO might avoid both PSD and NSPS applicability by adding or enhancing pollution control equipment, or in the case of PSD, restricting

operations below maximum potential such that the emissions increases necessary to trigger applicability would not occur. The WEPCO should discuss its plans in this regard with EPA. Third, regarding NSPS applicability to unit 1, additional information is necessary to determine whether a physical or operational change would occur.

Thus, although this memorandum will serve to answer many of the questions necessary to reaching final determinations, you should advise WEPCO that ultimately applicability depends upon changes in emissions after the renovations and whether the company decides to take the steps which would enable it to lawfully avoid coverage. Also, NSPS coverage of unit 1 can only be determined after an evaluation of the additional information regarding the work to be performed. In addition, as to NSPS, WEPCO should be advised to submit a formal request pursuant to 40 CFR 60.5 if it desires a final applicability determination.

As the need for further factual development here suggests, determinations of PSD and NSPS applicability are fact-specific, and must be made on a case-by-case basis. This memorandum provides a framework for analyzing the proposed changes at Port Washington and gives EPA's views on relevant issues of legal interpretation. It should also be useful in assessing other so-called "life extension" projects in the future. However, any such project would need to be reviewed in light of all the facts and circumstances particular to it. Thus, a final decision regarding PSD and NSPS applicability here would not necessarily be determinative of coverage as to other life extension projects.

If you have any further questions regarding the discussion or conclusions in this memorandum, please have your staff contact David Solomon of the New Source Review Section at FTS 629-5375.

I. Background

As mentioned in your March 25 request, the five coal-fired units at Port Washington began operation in 1935, 1943, 1948, 1949, and 1950, respectively. Each unit was initially rated at 80 megawatts electrical output capacity. In recent years, however, the performance of the units began to deteriorate due to age-related degradation of the physical plant. In particular, inspections performed by a WEPCO consultant in 1984 revealed extensive cracks originating from the internal surfaces of the rear steam drums and boiler bank boreholes in units 2, 3, 4, and 5, creating significant safety concerns. Because of these safety concerns and other age-related problems, in 1985 the operating levels of units 2, 3, and 4 were reduced, and unit 5 was removed from service. As a result of the plant's deteriorating condition, the maximum rated physical capacities of units 1, 2, 3, and 4 at this time are 45, 65, 75, and 55 megawatts, respectively.

The life extension project includes extensive capital improvements to the common facilities and each of the individual units, including replacement of the rear steam drum in units 2, 3, 4, and 5. The renovation work will restore the physical and operational capability of each unit to its original 80 megawatt nameplate capacity, and extend the useful life of the units well beyond the planned retirement dates that would otherwise apply. Upon completion of the project, WEPCO intends to substantially increase the actual operations at the Port Washington plant.

II. PSD Applicability

The life extension project at Port Washington is subject to preconstruction review and permitting under the Act's PSD provisions if it is a "major modification" within the meaning of the Act and EPA's regulations. The PSD regulations at 40 CFR 52.21 govern this determination because Wisconsin has been delegated PSD permitting authority under the provisions of 52.21(u). The definition of "major modification" in 52.21(b)(2)(i) requires an analysis of several factors. These factors may be grouped under two general questions. Will the work entail a "physical change in or change in the method of operation of a major stationary source"? If so, will the change "result in a significant net emissions increase of any pollutant subject to regulation under the Act" [see 52.21(b)(2)(i)]? The Port Washington facility is an existing major stationary source because it emits well in excess of the PSD threshold amount for several pollutants.

A. Physical Change or Change in the Method of Operation

This requirement of a major modification is satisfied if either a physical or operational change would occur.

1. Physical Change

The renovation work called for under the proposed life extension project at Port Washington would constitute a "physical change" at a major stationary source. The clear intent of the PSD regulations is to construe the term "physical change" very broadly, to cover virtually any significant alteration to an existing plant. This wide reach is demonstrated by the very narrow exclusion provided in the regulations: other than certain uses of alternate fuels not relevant here, only "routine maintenance, repair and replacement" is excluded from the definition of physical change [see 52.21(b)(2)(iii)(a)].

In determining whether proposed work at an existing facility is "routine," EPA makes a case-by-case determination by weighing the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding. In this case, all of these factors suggest that the work required under WEPCO's life extension project appears not to be "routine." The available information indicates that the work proposed at Port Washington is far from being a regular, customary, or standard undertaking for the purpose

of maintaining the plant in its present condition. Rather, this is a highly unusual, if not unprecedented, and costly project. Its purpose is to completely rehabilitate aging power generating units whose capacity has significantly deteriorated over a period of years, thereby restoring their original capacity and substantially extending the period of their utilization as an alternative to retiring them as they approach the end of their useful physical and economic life. The most important factors that would support these conclusions are outlined below.

a. The project would involve the replacement of numerous major components. The information submitted by WEPCO shows that the company intends to replace several components that are essential to the operation of the Port Washington plant. In particular, as noted above, WEPCO would replace the rear steam drums on the boilers at units 2, 3, 4, and 5. According to WEPCO, these steam drums are a type of "header" for the collection and distribution of steam and/or water within the boilers. They measure 60 feet long, 50.5 inches in diameter, and 5.25 inches thick, and their replacement is necessary to continue operation of the units in a safe condition. In addition, at each of the emissions units, WEPCO plans to repair or replace several other integral components, including replacement of the air heaters at units 1, 2, 3, and 4. The WEPCO also plans to renovate major mechanical and electrical auxiliary systems and common plant support facilities. The WEPCO intends to perform the work over a 4-year period, utilizing successive 9-month outages at each unit.

In its July 8, 1987 application for authority to renovate to the Public Service Commission of Wisconsin (PSC), WEPCO described the life extension project and explained its purpose and necessity. The WEPCO took care to distinguish the proposed renovation work from routine maintenance that did not require PSC approval, explaining that:

> . . . [work items] falling into the category of repetitive maintenance that are normally performed during scheduled equipment outages do not require specific commission approval and, accordingly, are not included in this application.

Thus, WEPCO's own earlier characterization of this project supports a finding that the planned renovations are not routine.

b. The purpose of the project is to significantly enhance the present efficiency and capacity of the plant and substantially extend its useful economic life. In its application to the PSC, WEPCO pointed out that due to age-related deterioration, total plant capability had declined by 40 percent. The company noted that the currently planned retirement dates for the Port Washington units, as set forth in its Advance Plan filed with the State, ranged from 1992 to 1999. However, WEPCO asserted that "extensive renovation of the five units and the plant common facilities is needed if operation of the plant is to be continued." In any event, WEPCO stated that the renovation work would allow the Port Washington plant to generate power at its designed capacity until the year 2010, and thus "represents a life extension of the units."

In contrast, in its July 29, 1988 letter to EPA headquarters (pages 9-13), WEPCO characterized the renovation work as the timely, routine correction of equipment problems--principally, the steam drum cracks. However, the information presented leads to the conclusion that this is not the case. While replacement of the steam drums is necessary to restore lost generating capacity, that is not the only work proposed to be done. Based upon maximum capacity figures for past years, it appears that the units had experienced deterioration in physical generating capacity even prior to the discovery of the steam drum cracks in 1984. Thus, WEPCO proposes a wide-ranging project encompassing a broad array of tasks that would not only correct the steam drum problem, but correct other age-related deterioration that is essentially independent of the steam drums. Such other work (e.g., replacement of air handlers) apparently is also necessary as a practical matter to restore original nameplate capacity. Thus, it appears that even if WEPCO had undertaken this renovation work immediately following discovery of the steam drum cracks, it would have been proper to characterize the proposed work as a nonroutine life extension project.[1]

c. The work called for under the project is rarely, if ever, performed. The WEPCO's application to the PSC asserted that the work to be performed under the life extension project was not frequently done:

> Generally, the renovation work items included in this application are those that would normally occur only once or twice during a unit's expected life cycle.

The EPA asked WEPCO to submit information regarding the frequency of replacement of steam drums, the largest category of work item called for under the project. WEPCO reported that to date, no steam drums have ever been replaced at any of its coal-fired electrical generating facilities. WEPCO did point out that it had replaced other "headers" comparable in design pressure and function. However, the largest of these was 16 inches in

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[1]It is important to note in this regard that not all renovation, repair, or "life extension" projects would properly be characterized as modifications potentially subject to PSD and NSPS. For example, nonroutine repairs to correct unexpected equipment outages, even of major components such as steam drums, would not be subject to NSPS if they did not increase the maximum capacity of the affected facility as it existed prior to the outage. Conversely, undertaking a program of repair and maintenance properly characterized as routine would not subject a facility to the Act's requirements.

diameter, and EPA does not believe that they are comparable in diameter, wall thickness, function, or importance to the rear steam drums at Port Washington.[2]

d. The work called for under the project is costly, both in relative and absolute terms. The latest information supplied by WEPCO is that the renovation work at Port Washington will cost $87.5 million, of which at least $45.6 million is designated as capital costs.[3] The WEPCO reports that, in terms of annualized costs, the renovation project will cost $7.8 million, as compared to $51.6 million for a new 400 megawatt plant. Thus, renovation costs represent approximately 15 percent of replacements costs.

2. Change in the Method of Operation

The renovation work at Port Washington would not constitute a "change in the method of operation" within the meaning of the PSD regulations. However, it is clear that the "physical change" and "operational change" components of the "major modification" definition are discrete and independent. Thus, as explained below, PSD still applies if there is a physical change that will significantly increase net emissions.

In addition, the regulations exclude from the definition of physical or operational change "an increase in the hours of operation or in the production rate" [see 40 CFR 52.21(b)(2)(iii)(f)]. The preamble to the rule [45 FR 52676, 52704 (August 7, 1980)], makes it clear that this exclusion is intended to allow a company to lawfully increase emissions through a simple change in hours or rate of operation up to its potential to emit (unless already subject

[2]The WEPCO's July 29, 1988 letter to EPA stated (on page 13) that after further investigation, the company "learned of several examples" of steam drum failure and replacement. However, WEPCO provides no further details, other than noting that in one instance, the drum failed during initial testing and was replaced. Replacement of a failed component at a new facility presumably would not increase emissions from the facility, and probably would be viewed as routine if the alternative was to forego operation of that new facility. Under such circumstances, it is unlikely that the replacement would trigger the Act's requirements.

[3]The WEPCO's July 8, 1987 application to the PSC included a project cost estimate of $83.9 million, of which $45.6 million was designated as capital costs. A more recent cost estimate provided to EPA by WEPCO indicates that several work items are now deemed unnecessary, such that the cost of the original project is now estimated at $70.5 million. However, all but $89,000 of these reductions are designated as "maintenance" items. The recent submission also relates that the scope of the original project has now been expanded to include flue gas conditioning equipment and associated air heater work costing approximately $17 million. Although WEPCO has not broken down these additional costs into capital and maintenance (or "expense") expenditures, it would appear that most, if not all, of this additional work would be classified as capital costs. Thus, it is highly likely that actual capital costs would be significantly higher than $45.6 million.

to any federally enforceable limit) without having to obtain a PSD permit. Thus, emissions increases at Port Washington associated with increased operations would not, standing alone, subject WEPCO to PSD requirements. However, as discussed in greater detail below, the exclusion for increases in hours of operation or production rate does not take the project beyond the reach of PSD coverage if those increases do not stand alone but rather are associated with non-excluded physical or operational changes.

In its March 17, 1988 letter to Region V and its July 29, 1988 letter to EPA Headquarters, WEPCO asserted that the exclusion for increases in operational hours or production rate also would serve to render PSD review not applicable to the renovation work proposed at Port Washington because the project's purpose was to restore the original design capacity of 80 megawatts per unit, but not to exceed that level. However, a plant's original design capacity is irrelevant to a determination of PSD applicability.

B. Significant Net Emissions Increase

Under the PSD regulations, whether the life extension project at Port Washington would result in a "significant net emissions increase" depends on a comparison between the "actual emissions" before and after the physical changes resulting from the renovation work. Where, as here, the source has not yet begun operations following the renovation, "actual emissions" following the renovation are deemed to be the source's "potential to emit" [see 40 CFR 52.21(b)(21)(iv)]. Apparently, there would be a "significant net emissions increase" within the meaning of the PSD regulations as a result of the proposed renovations as currently planned, because potential emissions after the project--reflecting the restoration of 80 megawatt capacity at each unit--would greatly exceed representative actual emissions prior to the physical changes. (The fact that the project is intended to restore the plant's original design capacity is irrelevant to that calculation.)[4] If this is so, the project would be a "major modification" subject to PSD review. However, PSD applies on a pollutant-specific basis, and EPA has not been furnished with adequate data regarding the impact of the proposed renovations on the various pollutants to determine whether a significant net emissions increase would indeed occur for any pollutant. Such data must be provided before EPA can make a final determination of PSD applicability.

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[4]The WEPCO also contends (July 29, 1988 letter, page 35) that EPA should instead compare representative actual emissions prior to the change with "projected" actual emissions after the renovations. The PSD regulations provide no support for this view. Where, as here, a source is not currently subject to a PSD permit containing operational limitations, EPA must presume that the source will operate at its maximum capacity and, hence, its maximum potential to emit. However, as discussed below, a source is entitled to reduce its potential to emit by embodying its "projections" of future emissions in federally enforceable restrictions on its operations that may serve to lawfully avoid PSD review.

It is important to note in this regard that WEPCO, at its option, could "net out" of PSD review by accepting federally enforceable restrictions on its potential to emit after the renovation. This could occur through enhancement of existing pollution control equipment, addition of new equipment, acceptance of federally enforceable operational restrictions, or some combination of these measures, limiting potential emissions to a level not significantly greater than representative actual emissions prior to the renovations. Theoretically, WEPCO could minimize the needed restrictions on its potential to emit following the renovations if it could show that some period other than the most recent two years is "more representative of normal source operation" [see 52.21(b)(21)(ii)]. (Obviously, such a showing would be most important with respect to unit 5, because it has been shut down and has had zero emissions since 1985.) Since these matters are within WEPCO's control, you should advise the company to enter discussions with Region V and Wisconsin, as appropriate, if WEPCO desires to "net out" of PSD review.

The WEPCO also argued in its July 29, 1988 letter, at pages 33-41, that even if EPA is correct that the Port Washington life extension project would involve physical changes within the meaning of the PSD regulations, any emissions increases would be due to increased production rates or hours of operation rather than higher emissions per unit of production. Therefore, WEPCO contends that these increases should be excluded from consideration in determining whether a net significant emissions increase and, hence, a major modification, would occur. The WEPCO is incorrect in this regard.

As noted above, the exclusions cited by WEPCO are intended to apply where a source increases emissions by simply combusting a larger amount of fuel, or processing a larger amount of raw materials during a given time period, or by expanding its hours of operation "to take advantage of favorable market conditions" (see 45 FR 52704). In this instance, however, it is obvious that WEPCO's plans to increase production rate or hours of operation are inextricably intertwined with the physical changes planned under the life extension project. Absent the extensive renovations proposed at Port Washington, WEPCO would have little market incentive to, and in part would be physically unable to, increase operations at these aged and deteriorated facilities which, absent the renovations, would likely be retired from service in the near future. Thus, WEPCO's plans call for precisely the type of "change in hours or rate or operation that would disturb a prior assessment of a source's environmental impact [and] should have to undergo [PSD review] scrutiny" (see 45 FR 52704). Conversely, accepting WEPCO's interpretation of the major modification regulations would serve to exclude from consideration all physical or operational changes except those which cause increased emissions per unit of production. Clearly, EPA never intended this result. It would allow, through substantial capital investment, significant expansion of the pollution-emitting capacity and longevity of major industrial facilities without PSD review of the impacts on air quality and opportunities for future economic growth.

C. Baseline Date

The November 9, 1987 letter from the Wisconsin Department of Natural Resources to Region V asked whether a complete March 28, 1986 PSD permit application for certain work at Port Washington triggered the PSD baseline date, despite the fact that the permit was never issued. The answer to this question is yes. Baseline dates are triggered by the first complete application and remain in effect regardless of whether the application is revised or withdrawn, or whether the permit is finally issued and the source constructed or modified.

III. NSPS Applicability

The Port Washington renovations are subject to the Act's NSPS if they constitute "modifications" within the meaning of section 111 and 40 CFR Part 60. Under 60.1, the NSPS applies to modifications at an "affected facility." Each unit at Port Washington is properly characterized as an "affected facility" subject to the NSPS at 40 CFR Part 60, Subpart Da, which applies to electric utility steam generating units [see 60.40(a)]. Pursuant to 60.14(a), a modification for NSPS purposes is defined as "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies." Increase in emission rate is in turn defined as an increase in kilograms per hour (kg/hr) [see 60.14(b)].

Pursuant to longstanding EPA interpretations, the emission rate before and after a physical or operational change is evaluated at each unit by comparing the hourly potential emissions under current maximum capacity to emissions at maximum capacity after the change. In addition, under the Act's NSPS provisions, only physical limitations on maximum capacity are considered in determining potential emissions at power plants. Thus, any prospective changes in fuel or raw materials accompanying the physical or operational change are not considered in determining maximum capacity. Consequently, 60.14(b)(2) requires that, in conducting emissions tests before and after a change to determine whether an increase in emission rate has occurred, "operational parameters" which may affect emissions must be held constant. Fuel and raw materials are "operational parameters" for this purpose. Similarly, 60.14(e)(4) provides that use of an alternative fuel or raw material which the existing facility was designed to accommodate before the change would not be considered a modification. Thus, for example, a physical change which increases the maximum capacity of the facility would have a corresponding increase in the sulfur dioxide emissions if the facility used fuel with the same sulfur content before and after the change. Such a prospective increase cannot be offset by instead using fuel with a lower sulfur content after the change, because, under the regulations, the facility would always have the option of changing back to the higher sulfur-content fuel at a later date without triggering a modification for NSPS purposes. However, any offsetting reductions in emission rate caused by the concurrent addition of pollution control equipment would be considered in determining whether a physical or operational change results in an increase in emission rate.

The WEPCO contends (July 29, 1988 letter, at pages 20-27) that baseline capacity for the purpose of determining whether an increase in emission rate occurs for purposes of an NSPS modification is the original design capacity of the facility. This is incorrect. The thrust of the NSPS modification provisions is to compare actual maximum capacity before and after the change in question. Thus, original design capacity is irrelevant. The provision in 40 CFR 60.14(b)(2) for manual emission tests to determine whether an increase has occurred clearly contemplates that tests will be done just prior to and after the physical or operational change. The original design capacity of a unit, to the extent it differs from actual maximum capacity at the time of the test due to physical deterioration--and, hence, derating--of the facility, is immaterial to this calculation.

A. Physical or Operational Change

As with the Act's PSD provisions, a modification occurs for NSPS purposes, if there is either a physical or operational change [see 40 CFR 60.14(a)].

1. Physical Change

As is the case under the PSD provisions, the proposed renovations at Port Washington would constitute a physical change for NSPS purposes, at least at units 2, 3, 4, and 5. The WEPCO would need to supply more information, if EPA is to make a definitive determination as to unit 1.

The rear steam drums are part of the steam generating unit which constitutes the "affected facility" within the meaning of 40 CFR 60.41(a), and the drum replacements at units 2, 3, 4, and 5 are integral to the planned increase in maximum capacity, which is the purpose of the life extension project. With respect to unit 1, other physical changes would increase maximum capacity from 45 to 80 megawatts. However, there is some question whether those changes, in significant part, would occur at the steam generating unit or will be limited to the turbine/generator set, which is not part of the affected facility. We suggest that you pursue this matter with WEPCO to the extent necessary to determine NSPS applicability regarding unit 1.

As with PSD, the NSPS regulations exclude routine maintenance, repair, and replacement [see 60.14(e)(2)]. However, the renovations at the Port Washington steam generating units are not routine for NSPS purposes for the same reasons--detailed above--that they are not routine for PSD purposes.

2. Operational Change

Operational changes include both increases in hours of operation and increases in production rate. Section 60.14(e)(3) provides that an increase in hours of operation is not, by itself, a modification. However, an increase in production rate at an existing facility constitutes a modification, unless it can be accomplished without a capital expenditure on that facility [see 60.14(e)(2)].

It is highly likely that the life extension project at Port Washington constitutes an operational change under this standard, for two reasons. First, restoring nameplate capacity at units 1, 2, 3, and 4 presumably entails, among other things, changes that will allow the units to combust a larger amount of fuel at maximum capacity through operation at higher working pressures than the units have been able to accommodate in recent years. In the case of unit 5, the renovations presumably involve an increase over zero fuel and pressure. These changes constitute an increase in production rate within the meaning of the regulations. Second, as noted above in the discussion of PSD applicability, this increase in production rate entails substantial investments to improve the capital stock at each affected facility. It appears that these investments are large enough to qualify as "capital expenditures" under the formula specified in 60.2, although WEPCO should be asked to supply actual calculations should this become necessary to determine NSPS applicability.

B. Increase in Emission Rate

It seems clear that, absent some creditable offsetting changes, the increases in maximum generating capacity proposed for each of the Port Washington units would represent an increase in the hourly potential emission rate for each pollutant to which a standard applies over the emission rate prior to the renovation. As noted above, burning cleaner fuels would not be creditable. Similarly, voluntarily restricting the production rate following the renovations also would not be creditable for NSPS purposes, because WEPCO could, at a later date, increase production without triggering NSPS [see 40 CFR 60.14(e)(2)]. Accordingly, to avoid triggering NSPS, WEPCO would need to install additional air pollution control equipment, or upgrade existing equipment, to offset the potential emissions increases, such that no increase would occur at maximum capacity. The information submitted indicates that WEPCO may plan some enhancement of the current control equipment, but it is unclear whether this would be adequate to prevent an increase in emission rates. As with PSD applicability, such steps can lawfully avoid NSPS requirements. Accordingly, you should advise the company that it should address these contingencies if it desires EPA to rule on whether WEPCO can avoid NSPS requirements in this fashion.

C. Reconstruction

Based upon data provided by WEPCO, it seems that the Port Washington renovations would not qualify as a "reconstruction" for NSPS purposes under 40 CFR 60.15, because the capital cost for the upgrades to each of the five units, while substantial, apparently is less than 50 percent of the fixed capital cost of constructing a comparable, entirely new steam generating unit [see 60.15(b)(1)]. However, the modification and reconstruction provisions of NSPS are independent. The former provisions are intended to apply in circumstances where physical or operational changes which increase emissions make NSPS coverage appropriate at levels well below 50 percent of the capital cost of a replacement unit. Conversely, the reconstruction provisions are aimed at changes to an existing unit irrespective of associated emissions

increases, but trigger NSPS requirements only if the higher 50 percent level is reached. Thus, the suggestion made by WEPCO in its July 29, 1988 letter (at pages 14-15) that EPA must undertake rulemaking to amend the reconstruction regulations before NSPS could be applied to the Port Washington project is not well taken.

IV. Conclusion

In adopting the PSD and NSPS programs, Congress sought to focus air pollution control efforts at an efficient and logical point: the making of long-term decisions regarding the creation or renewal of major stationary sources. The Port Washington life extension project, as it has been presented to EPA, would involve a substantial financial investment at pollution-emitting facilities that may significantly increase potential emissions of air pollutants over a period well beyond the current life expectancy of those facilities. If the additional factual information called for in this memorandum shows that emissions increases would indeed result from this project, the project would be subject to PSD and NSPS requirements. Such a result would be in harmony with the broad policy objectives that Congress intended to achieve through these programs.

cc: Gerald Emison, OAQPS
Alan Eckert, OGC

Exhibit 8

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	)
	)
	)
Plaintiff,	)
	)
v.	)
	)
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY	)
	)
	)
Defendants.	)
	)

DECLARATION OF
BRUCE E. BIEWALD

(1) My name is Bruce Edward Biewald, and I am the President of Synapse Energy Economics Inc., a consulting company in Cambridge, Massachusetts specializing in analysis of electric power systems. I have nearly thirty years of experience advising state agencies, consumer and environmental advocates, utilities and others on issues related to the production and consumption of energy. I have testified in more than one hundred utility regulatory proceedings in twenty-six states and two Canadian provinces, in cases in State and Federal Courts, and in proceedings of the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission's Atomic Safety and Licensing Board. I have co-authored more than one hundred reports, including studies for the Electric Power Research Institute, the US Department of Energy, the US Environmental Protection Agency, the Office of Technology Assessment, the Ozone Transport Commission, the New England Governors' Conference, the New England Conference of Public Utility Commissioners, the National Association of Regulatory Utility Commissioners, and the United Nations Framework Convention on Climate Change. My

papers have been published in the Electricity Journal, Energy Journal, Energy Policy, Public Utilities Fortnightly, and numerous conference proceedings.

(2) As president of Synapse Energy Economics, I oversee a staff of twenty individuals, conducting many dozens of consulting assignments each year. Our work includes consulting projects dealing with electric industry restructuring, stranded costs, system benefits, market power, mergers and acquisitions, generation asset valuation and divestiture, rate cases, power plant costs and performance, power supply contracts and performance standards, electric power system reliability, renewable power generation, demand-side management, air emissions from power plants, and electricity market simulation modeling for price forecasting and market power analysis. Synapse's governmental clients include federal agencies such as the Environmental Protection Agency, state Attorneys General, Consumer Advocates, utility regulatory commissions, and a variety of cities and towns. We also work for a number of non-governmental consumer advocates and environmental organizations, as well as associations of agencies, foundations, and private clients.

(3) My experience with electric system simulation modeling began in 1981, on projects to evaluate the economics of power system expansion plans. My experience includes programming these computer models, applying them in various types of analyses, and critiquing the application of these models by others. My own modeling work has involved simulation modeling of electric systems throughout the United States, including the PacifiCorp system in the Northwest; the MAPP, MAIN, and ECAR regions of the Midwest; the MACC, New York, and New England system in the Northeast, the Entergy

and Southern Company systems in the South; and a large number of smaller regions and utility systems.

(4) In January of 2000, Synapse Energy Economics entered into a license agreement with Henwood Energy Services (now "Ventyx") for the use of PROSYM. Synapse has applied PROSYM (now "Market Analytics") in a dozen different projects for clients including the US Environmental Protection Agency, the Ozone Transport Commission, the Arkansas Public Service Commission Staff, the Vermont Department of Taxes, the Iowa Office of Consumer Advocate, the City of New York, and a number of environmental organizations. My staff have been trained to run models including STRATEGIST, PROSYM, and PROMOD.

(5) Prior to founding Synapse, I was with Energy Systems Research Group (later Tellus Institute) where I was the manager of the electricity program, and consulted on a wide range of electric system regulatory and economic issues. I have a B.S. from the Massachusetts Institute of Technology where I studied Architecture, Building Technology, and Energy Use in Buildings.

(6) I have been asked to examine documents related to simulation model runs prepared by Detroit Edison Company ("Detroit Edison" or "the Company") focusing on the projected operation of Monroe Unit 2. Appendix A is a detailed statement of my qualifications and a listing of past testimony, papers and reports. I am being compensated $160 per hour for my work on this matter.

(7) In the paragraphs that follow I describe the PROMOD simulation model, and Detroit Edison's model run for its Power Supply Cost Recovery ("PSCR") filing with the

Michigan Public Service Commission, the regulatory agency in charge of determining what rates and costs Detroit Edison recovers from its Michigan ratepayers. In that model run, the projected availability of Monroe 2 is improved relative to the baseline period, and the generation from Monroe 2 increases. This increase in generation cannot be attributed to growth in demand, since the Company's projection of system demand is for a considerable decline in sales.

(8) The Company runs the PROMOD model for purposes of its annual Power Supply Cost Recovery (PSCR) filings with the Michigan Public Service Commission, among other purposes. PROMOD is a "dispatch" or "production costing model" that simulates the economic dispatching of electricity generating resources to meet customer loads. Economic dispatch is the principle that electric utilities dispatch – or "turn on" – power plants with low operating costs before they dispatch power plants with higher operating costs (subject to various system constraints). Input data to PROMOD includes customer electricity demand, generating unit capacity rates, forced outage rates, planned outages, fuel costs, and O&M costs. The core of the simulation is the way in which the fleet of generating units is operated to serve customer loads throughout a particular time period. The model outputs can include tables of the amount of electricity generation and fuel consumption by generating unit, the amount of air emissions of various types by generating unit, and the operating costs (fuel and O&M) for generating units.

(9) The PSCR cases are focused on the Company's costs of fuel and purchased power, and regulatory determination of the reasonableness of those costs for recovery from customers. It is central to the purpose of a PSCR case to have an accurate simulation of the system dispatch and the utilization of Detroit Edison's generating units.

(10) The Company's March 12, 2010, and June 3, 2010, letters (to Michigan Department of Environmental Quality and US EPA Region 5, respectively) present information on the projected operation of Monroe 2, and make reference to the 2010 PSCR PROMOD runs as the basis for those projections.

(11) A table attached to the Company's March 12 letter lists an annual capacity factor for Monroe 2 for the baseline period (May 2005 to April 2007) at 85.5% and a projected capacity factor for calendar year 2013 at 82.5%. The June 3 letter corrects the baseline capacity factor number to 72.2% (noting that 85.5% is actually the equivalent availability factor for that baseline period) and provides some limited additional information about the PROMOD inputs and projections.

(12) The projected annual capacity factor and equivalent availability factors according to the June 3 letter are as listed in the "EAF" and "CF" columns of the following table.

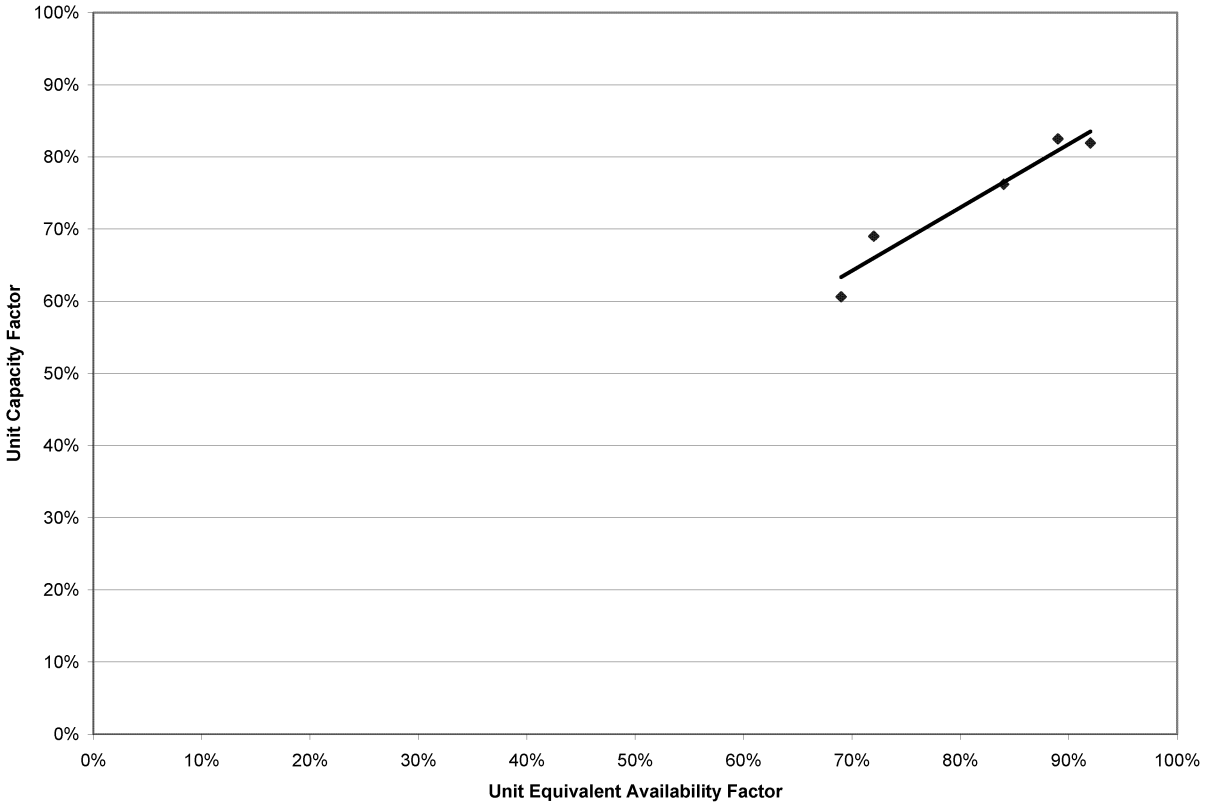
Table 1. Monroe 2 PROMOD data

	EFOR	EAF	CF	UF
2010	9.5%	69%	60.6%	88%
2011	8.3%	92%	81.9%	89%
2012	8.7%	84%	76.2%	91%
2013	8.7%	89%	82.5%	93%
2014	8.9%	72%	69.0%	96%

(13) The 2010 EAF and CF are lower than those predicted for other years because of the planned outage (to conduct the plant modification that is at issue in this case).

(14) The right hand column in the table above, labeled "UF," lists the utilization factor for Monroe 2, projected for the calendar years indicated. I calculated these UFs by dividing the CF by the EAF. The UF is a measure of the amount that a generating unit is utilized as a portion of the total amount of time that it is available, after accounting for forced and planned outages. I calculated the Monroe 2 UF for the May 2005 to April 2007 baseline period to be 84.4% (based on the CF and EAF specified by the Company in its March 12 and June 3 letters).

(15) Based upon the numbers for CF and UF in the table above, I conclude that Monroe is expected to be a highly utilized baseload unit. In addition, there is a reasonably direct relationship between the CF and EAF for Monroe in the Company's PROMOD run. That is, when EAF increases (the unit is more available) its CF also increases (the unit runs more). This is graphically clear from the x-y plot of the same CF and EAF data, below.



(16) The column in Table 1, above, labeled "EFOR" lists the equivalent forced outage rate input assumptions for Monroe 2 in the Company's PROMOD run.[1] These values, ranging from 8.3% to 9.5% represent a significant decrease (i.e., improvement in availability of the unit) relative to the EFORs calculated for the baseline periods by

[1] Detroit Edison's June 3, 2010, letter refers to these as "ROR" for "random outage rates" but here I will use the more commonly used terminology "EFOR" or "equivalent forced outage rate."

Ranajit (Ron) Sahu, using the data DTE reported to EPA. Mr. Koppe's calculations for the SO2 and NOx baseline periods put the outage rate at 14.5% and 16.6% respectively. The PROMOD EFOR inputs are slightly more than one half of these values.

(17) For the EAF, Mr. Koppe's calculations based on GADS data put the Monroe 2 EAF for the baselines periods at 81.3% and 79.3% (for SO2 and NOx, respectively). The PROMOD EAFs are well above this for the years 2011, 2012, and 2013.

(18) In the PROMOD model, as in the actual operation of an electric power system, plant availability will have a direct impact upon plant generation. Plant availability is input to the model in the form of planned outages and expected forced outage rate (FOR). Together the planned outages and the equivalent forced outage rate determine the "equivalent availability factor" or "EAF." As a general matter, a decreased forced outage rate means an increased EAF, and the increased EAF will result in a higher capacity factor for the unit. Moreover, the relationships among these variables tend to be linear. That is, with other variables constant in the model, the additional availability tends to be used according to a utilization factor for the unit. The additional generation typically results in increased fuel use and air emissions.

(19) There are other factors besides the EAF that can indirectly influence the capacity factor of a generating unit. These include the relative operating costs of generators (e.g., the economic dispatch order or loading order) and the system demand. In the case of Detroit Edison's projected operation of the Monroe units, from the limited information provided there is no indication of a large change in operating costs. There is a large change in projected system demand assumed in DTE's selected PROMOD run, but that change is

downward between the baseline period and the projection period in DTE's March 12, 2010 letter.

(20) The Company's forecast of system demand is presented in the Power Supply Cost Recovery testimony of Sherrie L. Siefman (MPSC Case No. U-16047). The actual and forecast system output, in millions of kWh, is as follows (from Ms. Siefman's Exhibit No A-8):

2003	55,800
2004	55,656
2005	58,117
2006	57,348
2007	58,128
2008	55,703
2009	51,041
2010	51,387
2011	51,763
2012	52,224
2013	52,331
2014	52,069

(21) In summary, the Company's PROMOD runs, which are the basis for the 2010 PSCR filing and for the March 12 and June 3 letters, show Monroe 2 generation increasing. This increase cannot reasonably be attributed to increases in demand, which is dropping precipitously according to the Company's forecast. The decrease to the unit's EFOR and improvement to unit availability is clearly a cause of the expected increase in generation.

(22) Appendix A contains my resume. Appendix B provides a list of considered documents.

I declare under penalty of perjury that the foregoing is true and correct.

Bruce E. Biewald

Executed on July 21, 2010 in Cambridge, Massachusetts.

APPENDIX A

BIEWALD RESUME

Bruce Edward Biewald
President
Synapse Energy Economics, Inc.
22 Pearl Street, Cambridge, MA 02139
(617) 661-3248 ext. 222 • fax: (617) 661-0599
www.synapse-energy.com
bbiewald@synapse-energy.com

PROFESSIONAL EXPERIENCE
Synapse Energy Economics, Inc., Cambridge, MA. President, 1996 to present.
Consulting on issues of energy economics, environmental impacts, and utility regulatory policy, including electric power system planning, air emissions, climate change policy, market power, mergers and acquisitions, generation asset valuation and divestiture, nuclear and fossil power plant costs and performance, renewable resources, power supply contracts and performance standards, green marketing of electricity, nuclear plant decommissioning and radioactive waste issues, environmental externalities valuation, energy conservation and demand-side management, electric power system reliability, avoided costs, dispatch modeling, economic analysis of power plants and resource plans, portfolio management, risk analysis and risk management.

Tellus Institute, Boston, MA. Senior Scientist and Manager of the Electricity Program, 1989 to 1996, Research Associate and later Associate Scientist, 1980-1988.
Responsible for research and consulting on all aspects of electric system planning, regulation, and restructuring.

EDUCATION
Massachusetts Institute of Technology,
BS 1981, Architecture, Building Technology, Energy Use in Buildings.
Harvard University Extension School,
1989/90, Graduate courses in micro and macroeconomics.

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS
Expert testimony on energy, economic, and environmental issues in more than one hundred utility regulatory proceedings in twenty six states and two Canadian provinces, in cases in State and Federal Courts, and in proceedings of the Federal Energy Regulatory Committee and the Nuclear Regulatory Commission's Atomic Safety and Licensing Board.

Co-author of more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the National Association

of Regulatory Utility Commissioners, and the United Nations Framework Convention on Climate Change.

Papers published in the Electricity Journal, the Energy Journal, Energy Policy, Public Utilities Fortnightly, and numerous conference proceedings.

Invited to speak by American Society of Heating, Refrigerating, and Air-Conditioning Engineers, American Society of Mechanical Engineers, International Atomic Energy Agency, National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Consumer Law Center, the Latin American Energy Association (OLADE), the Swedish Environmental Protection Agency (SNV), the U.S. Environmental Protection Agency, the European Federation of Clean Air and Environmental Protection Associations, and others.

TESTIMONY

United States District Court for the North District of Alabama (Civil Action No 2:01-CV-00152-VEH) United States v. Alabama Power Company – December 2009
Expert report on use of computer models for electric system planning and projections of generating unit operations. Also rebuttal report in May 2010.

United States District Court for the Eastern District of Kentucky, Lexington Division (Case 5:05-cv-0075-KSF) United States v. Kentucky Utilities Company – October 2008
Expert report on use of computer models for electric system planning, capital investment planning and economic analysis, and projections of generating unit operations.

Nova Scotia Utility and Review Board – August 2008
Review of rate case issues; power plant depreciation and load forecasting.

Nova Scotia Utility and Review Board – March 2008
Review of Nova Scotia Power Inc.'s demand-side management plan.

Indiana Utility Regulatory Commission (Cause Nos. 43114 and 43114S1) – May 2007
Review of IGCC Plant Proposal by Duke Energy Indiana and Vectren Testimony of Synapse Witnesses. Also cross answering testimony later in the month.

California Public Utilities Commission (Docket No. R.06-02-013) – March 2007
Joint testimony with William Steinhurst and Rick Hornby on electric utility long-term planning and procurement, including procurement strategy, treatment of carbon dioxide emissions, credit and collateral policies, customer risk tolerance, and resource needs.

New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006
Joint testimony with Bob Fagan and David Schlissel on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.
Indiana Utility Regulatory Commission (Cause Nos. 42861) – October 2005

Vectren (SIGECO) environmental compliance planning, including climate change policy and carbon price forecasting, energy efficiency and renewables as compliance options, and cost recovery issues.

United States District Court for the Eastern District of Kentucky, Lexington Division (Civil Action No.04-34-KSF, United States v. East Kentucky Power Cooperative – September 2005
Expert report on state regulation of electric utilities, use of computer models for system planning, capital investment planning and economic analysis, and projections of generating unit operations.

United States District Court for the Southern District of Indiana (Civil Action No.IP99-1693 C-M/S, United States v. Cinergy – May 2005
Expert report on state regulation of electric utilities, forecasting sales and resource requirements, use of computer models for system planning, capital investment planning and economic analysis, projections of generating unit operations, and the relationship between generator availability and output. Also, rebuttal report in September.

Federal Energy Regulatory Commission (Docket No. EC05-43-000) – April 2005
Market power analysis of the proposed merger of Exelon Corporation and Public Service Enterprise Group Incorporated. (Joint affidavit with David Schlissel.)

Nuclear Regulatory Commission Atomic Safety and Licensing Board (Docket No. 52-007-ESP and ASLBP No. 04-821-01-ESP) – April 2005
Affidavit on the environmental impacts and economic costs of a proposed new nuclear power project and alternatives.

Indiana Utility Regulatory Commission (Cause Nos. 42622 and 42718) – March 2005
Public Service Company of Indiana environmental compliance planning, including cost estimates for emission control technologies, climate change policy and carbon price forecasting, energy efficiency and renewables as compliance options, power plant retirement economics, and cost recovery issues.

National Research Council, Division on Engineering and Physical Sciences, Board on Energy and Environmental Systems (Project No. BEES-J-03-03-A) – March 2005
Alternatives for replacing the generation of the Indian Point Energy Center nuclear facility.

Georgia Public Service Commission (Docket No. 18300-U) – October 2004
Georgia Power Company's cost of service study, treatment of electrical distribution equipment, and proposed rates for the Metropolitan Atlanta Rapid Transit Authority.

Texas Public Utility Commission (Docket No. 29526) – June 2004
Issues in CenterPoint Energy Houston Electric LLC's true up filing, including environmental cleanup costs, excess mitigation credits, and construction work in progress. Also rebuttal testimony on June 14.

Texas Public Utility Commission (Docket No. 28818) – April 2004

The Independent Transmission Operator proposal of Energy Gulf States Utilities, Inc. (prefiled testimony adopted by Paul Peterson).
Indiana Utility Regulatory Commission (Cause No. 42359) – August 2003
Public Service Company of Indiana rate making issues including the impact of trackers on risks to shareholders and customers, costs of environmental compliance, treatment of merchant plant investment and risk, and joint dispatch issues.

Nevada Public Utilities Commission (Docket No. 03-1014) – April 2003
Review of Sierra Pacific Power Company's risk management and procurement of electric power in the wholesale markets.

Nevada Public Utilities Commission (Docket No. 02-11021) – March 2003
Review of Nevada Power Company's risk management and procurement of electric power in the wholesale markets.

United States District Court for the Southern District of Illinois (Civil Action No. 99-833-MJR, United States v. Illinois Power Company and Dynegy Midwest Generation, Inc.) – August 2003
Testimony at trial on analysis and opinions in rebuttal report dated October 2002 on use of computer models for system planning, projections of generating unit operations, and the relationship between generator availability and output.

State of Vermont, Windham Superior Court (Appeal of USGen New England, Inc. from 2001 Property Valuation by the Town of Rockingham) – September 2002
Electricity market prices and economic valuation of hydroelectric generating plant.

United States District Court for the Middle District of North Carolina (Civil Action No. 1:00 CV 1262, United States v. Duke Energy Corporation) – August 2002
Expert report on use of computer models for system planning, projections of generating unit operations, and the relationship between generator availability and output. (Joint report with Phil Hayet.)

Indiana Utility Regulatory Commission (Cause No. 41746) – July 2002
Reply testimony on a rate case settlement agreement, dealing with issues including NiSource's financial condition, service quality, environmental commitment, and electric rate impacts.

Connecticut Department of Public Utility Control (Docket No. 00-12-13RE01) – July 2002
The proposed sale of Seabrook Nuclear Station to FPL Energy Seabrook, LLC. Market power issues and market modeling.

United States District Court for the Southern District of Indiana (Civil Action No. IP99-1692-C-M/S, United States v. Southern Indiana Gas and Electric Company) – June 2002
Declaration on confidential business information and competitive harm.

Nevada Public Utilities Commission (Docket No. 02-2002) – April 2002
Review of Sierra Pacific Power Company's risk management and procurement of electric power in the wholesale markets.

Vermont Public Service Board (Docket No. 6596) – March 2002
Used and useful policy issues, electricity market prices, and above market costs of the purchase from Hydro Quebec.

Nevada Public Utilities Commission (Docket No. 01-11029) – February 2002
Review of Nevada Power Company's risk management and procurement of electric power in the wholesale markets.

Vermont Public Service Board (Docket No. 6545) – January 2002
Economic analysis of the proposed sale of Vermont Yankee nuclear plant and an associated Purchased Power Agreement.

New Jersey Board of Public Utilities (Docket No. EM01050308) – September 2001
Analysis of the proposed merger between Conectiv and PEPCo. Also, surrebuttal testimony in November. (Joint testimony with David Schlissel.)

Indiana Utility Regulatory Commission (Cause No. 41954) – June 2001
System planning and joint operation in a partially deregulated context.

State of Vermont, Windham Superior Court (Dockets S 362-9-99 and S372-9-99) – May 2001
Deposition on electricity market prices and economic valuation of hydroelectric generating plant.

Federal Energy Regulatory Commission (Docket No. ER01-200-001) – April 2001
Termination of the Cinergy Operating Agreement, treatment of merger savings, and affiliate relationships. Also cross-answering testimony in April.

New Jersey Board of Public Utilities (Docket No. EM00110870) – April 2001
Analysis of the proposed merger between FirstEnergy and GPU. Also, supplemental testimony in April. (Joint testimony with David Schlissel.)

Vermont Public Service Board (Dockets Nos. 6120 and 6460 – March 2001
Used and useful policy issues, electricity market prices, and above market costs of the purchase from Hydro Quebec. Also, surrebuttal testimony in April.

United States District Court for the Northern District of New York (Civil Action No. 00-CV-1738) – January 2001
Affidavit on the issuance and trading of SO2 emission allowances under the Title IV of the Clean Air Act, in Clean Air Markets Group v. George E. Pataki et al.

Department of Energy (Docket No. EE-RM-500) – December 2000
Oral testimony on proposed rules for central air conditioner and heat pump energy conservation standards.

Illinois Commerce Commission (Docket No. 00-0361) – July 2000
Review of ComEd's funding for nuclear power plant decommissioning.

California Public Utilities Commission (Rulemaking 99-10-025) – July 2000
Distributed generation and related rate design issues. Also, rebuttal testimony in August.

Massachusetts Department of Environmental Protection – July 2000
Comments on reliability implications of proposed emission standards for power plants.

Arkansas Public Service Commission (Docket No. 00-048-R) – June 2000
Requirements for electricity market power analyses.

United States District Court for the Middle District of North Carolina (1:99CV00033) – March 2000
Expert report on replacement power costs in Carolina Power & Light Company vs. Yuasa Exide, Inc.

Illinois Commerce Commission (Docket No. 99-0115) – September 1999
Review of ComEd's nuclear power plant decommissioning cost estimates.

West Virginia Public Service Commission (Case No. 98-0452-E-GI) – August 1999
AEP and Allegheny Power restructuring, market power, divestiture of generation, electric system market price modeling, statistical analysis of comparable sales, and responsibility for stranded costs and gains.

Mississippi Public Service Commission (Docket No. 96-UA-389) – August 1999
Review of Entergy Mississippi, Inc. and Mississippi Power Company stranded cost filings, divestiture of generation, statistical analysis of comparable sales, responsibility for stranded costs and gains.

Connecticut Department of Public Utility Control (Docket No. 99-03-36) – July 1999
Connecticut Light and Power Company standard offer service, market prices for electricity and the influence of market power, simulation analysis of the New England electricity market.

Connecticut Department of Public Utility Control (Docket No. 99-03-35) – July 1999
United Illuminating Company standard offer service, market prices for electricity and the influence of market power, simulation analysis of the New England electricity market.

Utah Public Service Commission (Docket No. 98-2035-04) – June 1999
Cost savings expectations for the proposed merger of PacifiCorp and Scottish Power.

Washington Utilities and Transportation Commission (Docket No. UE-981627) – June 1999
Cost savings expectations for the proposed merger of PacifiCorp and Scottish Power and assessment of whether the merger is in the public interest.

Federal Energy Regulatory Commission (Docket Nos. EC98-40-00, et al.) – April 1999
Horizontal market power and barriers to entry in consideration of the proposed merger of American Electric Power Company and Central and South West Corporation.

Connecticut Department of Public Utility Control (Docket No. 99-03-04) – April 1999
Market power, market prices, and simulation modeling as related to the application of United Illuminating Company for recovery of stranded costs.

Connecticut Department of Public Utility Control (Docket No. 99-02-05) – April 1999
Market power, market prices, and simulation modeling as related to the application of Connecticut Light & Power Company for recovery of stranded costs.

Maryland Public Service Commission (Case No. 8797) – January 1999
Simulation analysis of the ECAR market and projected market prices for electricity for estimation of Potomac Electric Company's stranded generation costs and unbundled rates.

Maryland Public Service Commission (Case No. 8795) – December 1998
Simulation analysis of the PJM market and projected market prices for electricity for estimation of Delmarva Power and Light Company's stranded generation costs and unbundled rates.

Maryland Public Service Commission (Cases Nos. 8794 and 8804) – December 1998
Simulation analysis of the PJM market and projected market prices for electricity for estimation of Baltimore Gas and Electric Company's stranded generation costs and unbundled rates.

Vermont Public Service Board (Docket No. 6107) – September 1998
Excess capacity, used & useful, and the economics of Green Mountain Power's purchase from Hydro Quebec.

Mississippi Public Service Commission (Docket No. 96-UA-389) – September 1998
Analyses of market concentration and market power, behavior of affiliated companies, need for an independent system operator.

California Public Utilities Commission (Application No. 97-12-020) – July 1998
Nuclear power plant decommissioning and radioactive waste disposal. Also, rebuttal testimony in August.

Federal Energy Regulatory Commission (Docket No. EC97-46-000) – June 1998
Affidavit on market power implications of the proposed merger between Allegheny Power System and Duquesne Light Company.

New Jersey Board of Public Utilities (Docket Nos. EX4120585Y, EO97070460, and EO97070463) – March 1998
Economic and environmental benefits of energy efficiency, including estimation of marginal air emissions from the PJM System. (Joint testimony with Nathanael Greene, Edward Smeloff, and Thomas Bourgeois.)

Vermont Public Service Board (Docket No. 6018) – February 1998
Excess capacity and the economics of Central Vermont Public Service Company's purchase from Hydro Quebec.

Public Service Commission of Maryland (Case No. 8774) – February 1998
Market power implications of the APS-DQE merger.

Federal Energy Regulatory Commission (Docket Nos. OA97-237-000 and ER97-1079-000) – January 1998
Market power in New England electricity markets.

British Columbia Utilities Commission – November 1997
British Columbia Hydro and Power Authority Wholesale Transmission Services Application.

Pennsylvania Public Utility Commission (Docket R-00973981) – November 1997
West Penn Power Company Restructuring Plan. Environmental disclosure, consumer education, and allocation of default customers.

Pennsylvania Public Utility Commission (Docket R-00974104) – November 1997
Duquesne Light Company Restructuring Plan. Environmental disclosure, consumer education, nuclear decommissioning, and allocation of default customers. Also surrebuttal testimony in December 1997.

Mississippi Public Service Commission (Docket No. 97-UA-496) – November 1997
Petition of Mississippi Power Company for a Certificate of Public Convenience and Necessity Authorizing Construction of a Generating Plant in Jackson County.

Pennsylvania Public Utility Commission (Docket Nos. R-00973953 and P-00971265) – November 1997
Application of PECO Energy Company for approval of its restructuring plan and petition on Enron Energy Services Power, Inc. for approval of an electric competition and customer choice plan. Allocation of default customers.

Vermont Public Service Board (Docket No. 5983) – October 1997
Excess capacity and the economics of Green Mountain Power Company's purchase from Hydro Quebec. Also rebuttal testimony in December 1997 and supplemental rebuttal testimony in January 1998.

Pennsylvania Public Utility Commission (Docket No. R-00973953) – September 1997
Joint petition for partial settlement of PECO Energy Company's proposed restructuring plan and application for a qualified rate order. Environmental disclosure, nuclear decommissioning and spent fuel.

Pennsylvania Public Utility Commission (Docket No. R-00974009) – September 1997
Pennsylvania Electric Company's Restructuring Plan. Environmental disclosure, customer education, and nuclear issues.

Pennsylvania Public Utility Commission (Docket No. R-00974008) – September 1997

Metropolitan Edison Company's Restructuring Plan. Environmental disclosure, customer education, and nuclear issues.

Indiana Legislature, Regulatory Flexibility Committee -- September 23, 1997.
Testimony on "Electric Industry Restructuring To Benefit Consumers and the Environment: Stranded Costs, Nuclear Issues, and Air Emissions."

Pennsylvania Public Utility Commission (Docket No. R-00973954) – June 1997
Pennsylvania Power & Light Company's Restructuring Plan. Environmental disclosure, customer education, PJM market structure, nuclear decommissioning and spent fuel, rate design for stranded cost recovery. Also, surrebuttal testimony in August.

Pennsylvania Public Utility Commission (Docket No. R-00973953) – June 1997
PECO Energy Company's Restructuring Plan. Environmental disclosure, PJM market structure, nuclear decommissioning and spent fuel.

New York Public Service Commission (Case 96-E-0897) -- April 1997
Consolidated Edison Company's Plans for Electric Rate Restructuring. Analysis of market power in the New York City load pocket.

Pennsylvania Public Utility Commission (Docket No. R-00973877) -- February 1997
Application of PECO Energy Company for Issuance of a Qualified Rate Order. Nuclear power plant decommissioning costs, stranded cost recovery, and securitization.

New Hampshire Public Utilities Commission (DR 96-150) -- November 1996
Electric industry restructuring, including stranded costs, industry structure, market power, and nuclear issues.

Massachusetts Department of Public Utilities (96-100) -- July 1996
Nuclear plant stranded costs and decommissioning.

Vermont Public Service Board (5854) – July 1996
Electric industry restructuring, including stranded costs, industry structure, and environmental protection.

Ontario Energy Board (H.R. 23) -- June 1995
Electricity rate options (joint evidence with John Stutz).

Pennsylvania Public Utility Commission (R-00943271) -- April 1995
Discount rates and system benefits charge.

Colorado Public Utilities Commission (94A-516A) – January 1995
Construction of new generating resources.

Public Service Commission of Nevada (94-9002) – November 1994
Environmental and health impacts of a proposed power plant.

Nuclear Decommissioning Finance Committee of New Hampshire (93-001) – September 1994
Seabrook decommissioning cost, spent fuel storage, and cost collection methodology (joint testimony with William Dougherty).

Public Service Commission of Wisconsin (6630-CE-197 and 6630-CE-209) – September 1994
Point Beach externalities, economics, spent fuel storage, and aging (joint testimony with William Dougherty).

British Columbia Utilities Commission – August 1994
Greenhouse gas emissions and environmental externalities policy

Public Service Commission of Wisconsin (05-EI-14) – February 1994
Cost of decommissioning Point Beach and Kewaunee nuclear power plants. Also, rebuttal and surrebuttal testimony in February.

Delaware Public Service Commission (91-39) – September 1992
Nuclear and fossil power plant performance targets.

Massachusetts Department of Public Utilities (91-131) – December 1991
Internalization of environmental externalities, greenhouse gas valuation and policy.

Massachusetts Department of Public Utilities (91-131) – October 1991
Environmental externalities valuation, emissions effects and global warming.

Massachusetts Department of Public Utilities ((89-141, 90-73, 90-141, 90-194 and 90-270) – December 1990
The incorporation of environmental externalities in specific utility RFPs.

Massachusetts Department of Public Utilities (90-55) – June 1990
Costs and benefits of high-efficiency gas heating equipment.

Massachusetts Department of Public Utilities (86-36-G and 89-239) – March 1990
Environmental externalities of electric resources.

Florida Public Service Commission (890973-E1) – January 1990
Integrated energy planning, power plant emissions, and nuclear plant performance.

Pennsylvania Public Utilities Commission (R-891364) – October 1989
Generating capacity requirements of the Philadelphia Electric Company and the Pennsylvania-New Jersey-Maryland Interconnection.

Maryland Public Service Commission (8199) – October 1989
Performance standards for coal, oil, and nuclear power plants.

Michigan Public Service Commission (U-9172) – April 1989

Economic analysis of the Palisades Power Purchase Agreement. Ratepayer impacts, incentives, and implications for plant operation and decommissioning.

Pennsylvania Public Utility Commission (P-870216, P-880283, P-880284, and P-880286) – March 1989
Allegheny Power System planning and avoided costs.

Michigan Public Service Commission (U-8880) – February 1988
Detroit Edison Company power supply costs, economics of Fermi "buy-back" purchase, nuclear fuel expense, oil costs, and power transactions.

Michigan Public Service Commission (U-8866) – December 1987
Consumers Power Company power supply costs, including projections of oil prices and purchased power costs.

Pennsylvania Public Utility Commission (R-850220) – September 1987
Economic analysis of West Penn Power Company's participation in the Bath County Pumped Storage Project, and Allegheny Power System capacity reserve requirements. Also, surrebuttal testimony in October.

Arizona Corporation Commission (U-1345-85-367) – February 1987
Palo Verde decommissioning cost.

Michigan Public Service Commission (U-8545) – December 1986
Consumers Power Company power costs, projected cost of oil and purchased power, economic evaluation of the Big Rock Point nuclear unit.

Public Service Commission of Indiana (38045) – November 1986
Northern Indiana Public Service Company system reliability and excess capacity.

California Public Utility Commission (84-06-014 and 85-08-025) – July 1986
Diablo Canyon decommissioning cost and collection issues.

Michigan Public Service Commission (U-8042R) – June 1986
Review of Consumers Power Company system operations during 1985 and economic evaluation of the Big Rock Point nuclear unit.

Michigan Public Service Commission (U-8291) – April 1986
Detroit Edison Company power supply costs, application of a multi-area dispatch model.

Michigan Public Service Commission (U-8286) – February 1986
Consumers Power Company power supply costs, application of a multi-area dispatch model.

Maine Public Service Commission (85-132) – January 1986
Standard and long term rates for cogeneration and small power production. Surrebuttal testimony in February.

Arkansas Public Service Commission (84-249-U) – June 1985
Impact of the Grand Gulf nuclear unit upon Arkansas Power and Light Company and Middle South Utilities electricity production costs.

Kentucky Public Service Commission (8666) – February 1984
Production costing modeling issues.

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Avoided Energy Supply Costs in New England: 2009 Report, prepared for AESC/ Massachusetts Avoided Energy Supply Components Study Group by Rick Hornby, David White, Bruce Biewald, Chris James, Ben Warfield, and Max Chang of Synapse, and Paul Chernick, Carl Swanson, Ian Goodman, Bob Grace, and Jason Gifford, August 21, 2009.

Productive and Unproductive Costs of CO2 Cap-and-Trade: Impacts on Electricity Consumers and Producers, prepared for National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Rural Electric Cooperative Association, and American Public Power Association by Ezra Hausman, Jeremy Fisher, Lauri Mancinelli, and Bruce Biewald, July 15, 2009.

Incorporating Carbon Dioxide Emissions Reductions in Benefit Calculations for Energy Efficiency: Comments on the Department of Energy's Methodology for Analysis of the Proposed Lighting Standard, prepared for New York State Attorney General by Bruce Biewald, David White, Jeremy Fisher, Max Chang, and Lucy Johnston, May 13, 2009.

Cost and Benefits of Electric Utility Energy Efficiency in Massachusetts, prepared for the Northeast Energy Efficiency Council by Doug Hurley, Kenji Takahashi, Bruce Biewald, Jennifer Kallay, and Robin Maslowski, August 1, 2008.

Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation, prepared for U.S. Environmental Protection Agency by Ezra Hausman, Jeremy Fisher, and Bruce Biewald, July 23, 2008.

Don't Get Burned: The Risks of Investing in New Coal-Fired Generating Facilities, prepared for Interfaith Center on Corporate Responsibility by David Schlissel, Lucy Johnston, Jennifer Kallay, Christopher James, Anna Sommer, Bruce Biewald, Ezra Hausman, and Allison Smith, February 26, 2008.

Tufts Cove Waste Heat Recovery Project, prepared for the Nova Scotia Utility and Review Board by Bruce Biewald, Bill Powers, and Ben Warfield, December 4, 2007 and revised August 4, 2008.
Avoided Energy Supply Costs: 2007 Final Report, prepared for AESC / Massachusetts Avoided Energy Supply Components Study Group by Rick Hornby, Carl Swanson, David White, Paul Chernick, Bruce Biewald, and Jennifer Kallay, August 10, 2007.

The Deerfield Wind Project – Assessment of the Need for Power and the Economic and Environmental Attributes of the Project, prepared for PPM Energy by Ezra Hausman, Bruce Biewald, and Kenji Takahashi, August 1, 2006.

Portfolio Management: Tools and Practices for Regulators, prepared for the National Association of Regulatory Utility Commissioners by William Steinhurst, David White, Rick Hornby, Alice Napoleon, Amy Roschelle, and Bruce Biewald, October, 2006.

Incorporating Energy Efficiency into the ISO New England Forward Capacity Market: Ensuring the Capacity Market Properly Values Energy Efficiency Resources, prepared for Conservation Services Group by Paul Peterson, Doug Hurley, Tim Woolf, and Bruce Biewald, June 5, 2006.
Ensuring Delaware's Energy Future: A Response to Executive Order Number 82, prepared for the Delaware Public Service Commission Staff by the Delaware Cabinet Committee on Energy with technical assistance from Synapse Energy Economics, March 8, 2006.

The Proposed Broadwater LNG Import Terminal Response to Draft Environmental Impact Statement and Update of Synapse Analysis, prepared for the Connecticut Fund for the Environment and Save The Sound by Ezra Hausman, Bruce Biewald, Kenji Takahashi, and David Schlissel, January 22, 2007.

RPM 2006: Windfall Profits for Existing Base Load Units in PJM, prepared for the Pennsylvania Office of Consumer Advocate by Bruce Biewald, Ezra Hausman, Paul Peterson, and David White, February 2, 2006.

An RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon, prepared for Illinois Citizens Utility Board, by Ezra Hausman, Paul Peterson, David White, and Bruce Biewald, October 18, 2005.

Considering Climate Change in Electric Resource Planning: Zero is the Wrong Value, by Lucy Johnston, Amy Roschelle, Ezra Hausman, Anna Sommer, and Bruce Biewald, Rev 3, September 30, 2005.

Using Electric System Operating Margins and Build Margins in Quantification of Carbon Emission Reductions Attributable to Grid Connected CDM Projects, a Synapse Energy Economics, Inc. report for the United Nations Framework Convention on Climate Change, September 19, 2005.

Methods for Estimating Emissions Avoided by Renewable Energy and Energy Efficiency, a Synapse Energy Economics, Inc. report for the U.S. Environmental Protection Agency by Bruce Biewald and Geoff Keith, July 8, 2005.

Economic Impacts and Avoided Air Emissions from Renewable Generation and Efficiency Programs in New England, a Synapse Energy Economics, Inc. report for the Regulatory Assistance Project by William Steinhurst, Robert McIntyre, Bruce Biewald, Cliff Chen, and Kenji Takahashi. April 15, 2005.

Electric Price Forecasts for St. Lawrence Hydroelectric Generation, prepared for the International Joint Commission (IJC) by David White and Bruce Biewald, March 11, 2005.

A Responsible Electricity Future: An Efficient, Cleaner and Balanced Scenario for the US Electricity System, a Synapse Energy Economics, Inc. report for the National Association of State PIRGs, by Bruce Biewald, David White, Geoff Keith, and Time Woolf. June 11, 2004.

Electricity Prices in PJM: Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs, a Synapse Energy Economics, Inc. report prepared for the PJM Interconnection, L.L.C., by Bruce Biewald, William Steinhurst, David White, and Amy Roschelle. June 3, 2004.

Reply Comments in Docket No. 2004-147: Strategies for Procuring Residential and Small Commercial Standard Offer Supply in Maine, a Synapse Energy Economics, Inc. report prepared for the Maine Office of Public Advocate by Amy Roschelle, Bruce Biewald, and Paul Peterson. April 21, 2004.

Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers, a Synapse Energy Economics, Inc. report prepared for the Regulatory Assistance Project and the Energy Foundation, by Bruce Biewald, Tim Woolf, Amy Roschelle and William Steinhurst. October 10, 2003.

A Clean Electricity Strategy for the Hudson River Valley, a Report for the Hudson River Foundation by Synapse Energy Economics and Pace Law School Energy Project. Geoff Keith, Bruce Biewald, David E. White, and Fred Zalcman. October 2003.

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Comments on the RPS Cost Analyses of the Joint Utilities and the DPS Staff, a Synapse Energy Economics, Inc. report prepared for the Renewable Energy Technology and Environment Coalition by Bruce Biewald, Cliff Chen, Anna Sommer, William Steinhurst, and David E. White. September 19, 2003.

Modeling Demand Response and Air Emissions in New England, a Synapse Energy Economics, Inc. report prepared for the U.S. Environmental Protection Agency, by Geoff Keith, Bruce Biewald, David White, and Mike Drunsic, August 2003.

Cleaner Air, Fuel Diversity and High-Quality Jobs: Reviewing Selected Potential Benefits of an RPS in New York State, a Synapse Energy Economics, Inc. report prepared for the Renewable Energy Technology and Environment Coalition by Geoff Keith, Bruce Biewald, David White, Anna Sommer and Cliff Chen. July 28, 2003.

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Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants," a Synapse Energy Economics, Inc. report prepared for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

Predicting Avoided Emissions from Policies that Encourage Energy Efficiency and Clean Power, a Synapse Energy Economics, Inc. report prepared for the Ozone Transport Commission, by Geoff Keith and Bruce Biewald, June 24, 2002.

Survey of Clean Power and Energy Efficiency Programs, a Synapse Energy Economics report prepared for the Ozone Transport Commission, by Lucy Johnston, Geoff Keith, Tim Woolf, Bruce Biewald, and Etienne Gonin, January 14, 2002.

Updated Avoided Energy-Supply Costs for Demand-Side Management Screening in Massachusetts, a Resource Insight report for the AESC Study Group, by Paul Chernick, Susan Geller, Bruce Biewald, and David White, December 5, 2001.

Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets, a Synapse Energy Economics report for the Maryland Office of People's Counsel, the Pennsylvania Office of Consumer Advocate, the Delaware Division of the Public Advocate, the New Jersey Division of the Ratepayer Advocate, and the Office of the People's Counsel of the District of Columbia, by Paul Peterson, Bruce Biewald, Lucy Johnston, Etienne Gonin, and Jonathan Wallach, November 9, 2001.

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Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Energy Economics report prepared for the Union of Concerned Scientists, by Daniel Allen, Bruce Biewald, and David Schlissel, January 7, 2001.
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"Residential Real-Time Metering Technology for Electricity Restructuring," Daljit Singh and Bruce Biewald, presented at the National Training and Information Center conference, Chicago, September 1996.
"Competition and Environmental Impacts in the U.S. Electric Sector: Must Market Forces be Tamed?," presented at the International Society of Ecological Economics conference, Boston, August 1996.
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"Counting the Costs: Scientific Uncertainty and Valuation Perspective in EXMOD," Stephen Bernow, Bruce Biewald, William Dougherty, and David White, presented at technical meeting of the International Atomic Energy Agency, Vienna, Austria, December 4-8, 1995.
"Environmentally Targeted Objectives for Reducing Acidification in Europe," Energy Policy, C.A. Gough, P.D. Bailey, B. Biewald, J.C.I. Kuylenstierna and M.J. Chadwick, December 1994.
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"From Social Costing to Sustainable Development: Beyond the Economic Paradigm," Stephen Bernow, Bruce Biewald, and Paul Raskin, in Social Costs of Energy: Present Status and Future Trends, Proceedings of an International Conference held at Racine, Wisconsin, September 8-11, 1992. Edited by Olav Hohmeyer and Richard Ottinger. Published by Springer-Verlag, September 1994.
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"Modeling Renewable Electric Resources: A Case Study of Wind Power," Stephen Bernow, Bruce Biewald, and Daljit Singh, presented at WINDPOWER 1994, Sponsored by American Wind Energy Association, Minneapolis, Minnesota, May 9-13, 1994.

"National Climate Change Policy and Clean Air Act Compliance: A Case Study of Combined CO2/SO2 Reduction," Stephen Bernow, Bruce Biewald, Mark Fulmer, Tim Woolf, Kristen Wulfsberg, and Barry Solomon, in the proceedings of NARUC's 5th National Conference on Integrated Resource Planning, Kallispell, Montana, May 15-18, 1994.
"Modeling Renewable Electric Resources: A Case Study of Wind Reliability," Stephen Bernow, Bruce Biewald, and Daljit Singh, presented at the NARUC-DOE National Regulatory Conference on Renewable Energy, Savannah, Georgia, October 3-6, 1993.
"Environmental Sustainability as a Goal in Resource Planning and Policy," Stephen Bernow and Bruce Biewald, Office of Technology Assessment workshop, Washington, DC. April 1993.
"Climate Change and the U.S. Electric Sector," Bruce Biewald and Stephen Bernow, presented at NARUC's 4th National Conference on Integrated Resource Planning, Burlington, Vermont, September 1992.
"Coordinating Clean Air Act Compliance with Integrated Resource Planning: The Role of Externalities," Stephen Bernow, Bruce Biewald, and Kristin Wulfsberg, the Eighth NARUC Biennial Regulatory Information Conference, Ohio State University, Columbus, Ohio. September 9-11, 1992.
"Direct Environmental Impacts of Demand-Side Management," Stephen Bernow, Frank Ackerman, Bruce Biewald, Mark Fulmer, Karen Shapiro, and Kristin Wulfsberg, American Council for an Energy Efficient Economy (ACEEE) 1992 Summer Study, September 1992.
"Modeling Fuel Cycle and Site-Dependent Environmental Impacts in Electric Resource Planning," Stephen Bernow and Bruce Biewald, invited paper at OECD-IEA Expert Workshop on Life-Cycle Analysis of Energy Systems, Paris, France, May 18 and 19, 1992. Proceedings published OECD/IEA Paris, 1993.
"Computer Model Use in Energy Conservation Planning," presented at the Latin American Energy Organization (OLADE) Seminar on Power Systems Computer Modeling in Quito, Ecuador, September 23-25, 1991.
"Environmental Externalities Measurement: Quantification, Valuation and Monetization," Bernow, Biewald and Marron, in External Environmental Costs of Electric Power, proceedings of a German-American workshop, Ladenburg, FRG, October 23-25, 1991. Edited by Olav Hohmeyer and Richard Ottinger, published by Springer-Verlag (Berlin, Heidelberg, New York).
"Some Microcomputer Tools for Least Cost Integrated Energy Planning: ECO, LEAP and EDB," Bruce Biewald and Harvey Salgo, presented at workshop on Energy Pricing and Planning, Bratislava, Czechoslovakia, May 21-22, 1991.
"Confronting Uncertainty: Contingency Planning for Decommissioning," Bruce Biewald and Stephen Bernow, Chapter 18 of "Nuclear Decommissioning Economics," a special issue of The Energy Journal of the International Association for Energy Economics, Vol.12, March 1991.
"Avoided Emissions and Environmental Dispatch," Stephen Bernow and Bruce Biewald, presented at the Conference on "Demand-Side Management and the Global Environment," Arlington, Virginia, April 22-23, 1991.
"Environmental Benefits of DSM in New York: Long Island Case Study," Bruce Biewald and Stephen Bernow, presented at the Conference on "Demand-Side Management and the Global Environment," Arlington, Virginia, April 22-23, 1991.
"Full Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation," Stephen Bernow, Bruce Biewald and Donald Marron, the Electricity Journal, March 1991.
"EDB: A Flexible Database System for Energy-Environmental Analysis," Bruce Biewald, Michael Lazarus, and David Von Hippel, presented at International Atomic Energy Agency

(IAEA) Technical Committee Meeting on "Development of a Database for Comparative Health and Environmental Impacts of Various Energy Systems," in Vienna, Austria, October 15-19, 1990.
"Full Cost Economic Dispatch: Recognizing Environmental Externalities in Electric Utility System Operation," Stephen Bernow, Bruce Biewald, and Donald Marron, presented at NARUC Conference on Externalities, Jackson Hole, Wyoming, October 1990.
"An Assessment of Demand-Side Management Models and Their Use and Applicability in Canadian Utilities," Martin Adelaar and Bruce Biewald, in the proceedings of the Canadian Electrical Association Demand-Side Management Conference, Halifax, Nova Scotia, September 1990.
”Avoided Cost Contracts Can Undermine Least Cost Planning," Stephen Bernow, Bruce Biewald, and Donald Marron, Energy Policy, September 1990.
"Environmental Externalities Measurement: Quantification, Valuation, and Monetization," Stephen Bernow, Bruce Biewald, and Donald Marron, in the proceedings of the Seventh NARUC Biennial Regulatory Information Conference, September 1990.
“Do We Really Need Nuclear Generating Companies?," Public Utilities Fortnightly, June 7, 1990.
“Nuclear Power Economics: Construction, Operation and Disposal," Bruce Biewald and Donald Marron, March 1989.
"Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity," Stephen Bernow and Bruce Biewald, in the proceedings of the Sixth NARUC Biennial Regulatory Information Conference, September 1988.
"Nuclear Power Plant Decommissioning: Cost Estimation for Power Planning and Ratemaking," Stephen Bernow and Bruce Biewald, Public Utilities Fortnightly, October 29, 1987.
"Cost and Performance of Boiling Water Reactors," Stephen Bernow, Bruce Biewald and Tim Woolf, Public Utilities Fortnightly, August 1987.

PRESENTATIONS
(Note: Presentations that were accompanied by a written paper are listed in the section for “papers,” above.)

“The U.S. Power System: Economic and Regulatory Challenges to Reducing Greenhouse Gas Emissions from the World’s Largest Machine,” presentation at Design Continuum, December 3, 2008.
“Economics of Electric Sector CO2 Emissions Reduction: Making Climate Change Policy that People Can Live With,” presentation at the NASUCA 2008 Annual Meeting, November 18, 2008.
“Selected Topics from Avoided Energy Supply Costs in New England 2007 Final Report,” presentation at a MA DPU Technical Session, July 29, 2008.
“Prudent Planning and New Coal-Fired Generation,” presentation at the CERES 2008 Conference, April 29, 2008.
“Climate Change Policies in the Northeast - Carbon Emission Caps and Energy Cost,” presentation at the ASHRAE Winter Meeting, prepared for the American Society of Heating, Refrigerating and A/C Engineers, January 19, 2008.

"Efficiency and Renewable Energy for Carbon Constrained Electric Systems 2007," presentation at the NASUCA Annual Meeting, Anaheim, California, prepared for National Association of State Utility Consumer Advocates, November 12, 2007.
"Air Emissions Issues Associated DER in the Mid-Atlantic Region," presentation at the Mid-Atlantic State Energy and Environment Workshop on Distributed Energy Resources, September 27, 2007.
"Exploration of Costs for Load Side and Supply Side Carbon Caps for California," presentation at the Joint En Banc Hearing of PUC and CEC on Point of Regulation in the Electricity Sector (R.06-04-009), prepared for Regulatory Assistance Project, and California Public Utilities Commission, August 21, 2007.
"Portfolio Management: Tools and Practices for Regulators," presentation at the NARUC 2006 Summer Meeting in San Francisco, California, and for the Annual Convention in Miami, Florida, prepared for the National Association of Regulatory Utility Commissioners, July 2006 and November 2006.
"Electricity Price Increases: Causes, Effects, and Solutions," presentation at the Restructuring Roundtable, May 19, 2006.
"Forecasting and Using Carbon Prices in a World of Uncertainty," presentation to Electric Utilities Environmental Conference in Tucson, Arizona on January 22, 2006.
"Energy Efficiency in the Northeast," presentation at ACEEE National Conference on Energy Efficiency as a Resource, Berkeley, CA, September 27, 2005.
"The Shape of Things to Come: Incorporating Unproven Reserves of Efficiency Savings into Energy Models," presentation to the East Coast Energy Group, Washington, DC, November 10, 2004.
"Displaced Emissions from Renewables and Efficiency in the Northeast United States," presentation at a workshop convened by the Commission for Environmental Cooperation, the US Environmental Protection Agency, and the World Resources Institute, Washington DC, November 4, 2004.
"Electric Transmission Technical and Policy Issues," presentation at National Association of State Utility Consumer Advocates conference in Austin, Texas, June 14, 2004.
"Incorporating Renewable Generation into a Risk Management Strategy," presentation at the New England Conference of Public Utility Commissioners Symposium, Brewster, Massachusetts, May 25, 2004.
"Electricity Portfolio Management," presentation at Illinois State University Institute for Regulatory Policy Studies Conference on "Beyond 2006," Springfield, Illinois, May 20, 2004.
"Electricity Risk Management: Diversified Resource Portfolios," presentation at Electric Power Supply Association Meeting, Washington, D.C., May 6, 2004.
"Quantifying Emission Reductions from Local Government Actions," presentation to Metropolitan Washington Council of Governments Energy and Air Quality Conference, Washington DC, April 5, 2004.
"Electricity Portfolio Management," presentation to National Association of Regulatory Utility Commissioners' conference in Washington, D.C., March 9, 2004.
"Portfolio Management for Electricity," presentation at the Regulatory Assistance Project's workshop on portfolio management, Chicago, September 18, 2003.
"Issues in Estimating Electric System Displaced Emissions," presentation at the Commission for Environmental Cooperation Technical Meeting on Approaches to Estimating Environmental Benefits of Renewable Energy and Energy Efficiency, Washington, DC, July 27, 2003.

"Best Practices in Market Monitoring and Mitigation," presented at the National Association of State Utility Consumer Advocates Mid-Year Meeting in Austin, Texas, June 16, 2002.
"Regulation of Waste Management at Large Electric Utilities: Modeling Industry Impacts," US Environmental Protection Agency, August 7, 2001.
"Quality of Service in Performance-Based Regulation: US Experiences," presented at the Seminar on Regulation of Electricity Supply Quality, Milan, Italy, June 8, 2001.
"Demand Response in Electricity Markets," presented at the National Association of State Utility Consumer Advocates Mid-Year Meeting in Santa Fe, New Mexico, June 18, 2001.
Presentation on "Repowering the Midwest: The Clean Energy Development Plan for the Heartland," at the National Wind Coordinating Committee Upper Midwest Transmission Workshop, Minneapolis, Minnesota, May 1, 2001.
"Observations on New England's Electricity Markets," National Regulatory Research Institute Market Power Conference, Columbus, Ohio, April 10, 2001.
Presentation on "Derailing Coal: The Economics of Coal-Fired Electricity Generation in the U.S.," Tax Shift Strategy Meeting, Washington, D.C., December 2, 2000.
Presentation on "Repowering the Midwest: A Clean Energy Development Plan for the Heartland," presentation with Howard Learner at the National Association of Regulatory Utility Commissioners Annual Meeting, San Diego, California, November 14, 2000.
Presentation on "Electricity in New England: Market Imperfections of Failure?" at National Association of State Utility Consumer Advocates Annual Meeting, San Diego, California, November 13, 2000.
Presentation on "How Green is Green? Verifying Energy Advertising Claims," at the New England Conference of Public Utility Commissioners Symposium, Bretton Woods, New Hampshire, May 25, 1999.
Presentation on "Consumer Perspectives on Market Power – Case Studies from New England, New York, PJM, and Mississippi," IBC Conference on Market Power, Washington DC, May 24, 1999.
Presentation on "Grandfathering and Environmental Comparability," at the National Association of Regulatory Utility Commissioners 1998 Summer Committee Meetings, Seattle, July 26, 1998.
Presentation on "Tracking Electricity in the New England Market," at the National Association of Regulatory Utility Commissioners 1998 Summer Committee Meetings, Seattle, July 26, 1998.
Presentation on "Tracking Electricity in the New England Electricity Market," at the National Council on Competition and the Electricity Industry National Executive Dialogue on Customers' Right to Know, Chicago, May 13, 1998.
Presentation on "Comparable Environmental Regulations in a Restructured Electricity Industry: The Grandfathering Effect," National Association of Regulatory Utility Commissioners meeting in Washington, D.C., March 1, 1998.
Presentation on "Market Power in Electricity Generation," National Consumer Law Center Conference, Washington, D.C., February 9, 1998.
Presentation on "Electricity Market Power in New England," Massachusetts Electric Industry Restructuring Roundtable, Boston, December 15, 1997.
Presentation on wind power development and air quality, National Wind Coordinating Committee New England Wind Issues Forum, Boston, November 7, 1997.
Invited speaker on market power, National Association of State Utility Consumer Advocates meeting in Boston, November 12, 1997.

Presentation on “Distortions to Future and Current Competitive Electric Energy Markets Due to Grandfathering Environmental Regulations of Electric Power Plants,” National Association of Regulatory Utility Commissioners meeting in Boston, November 9, 1997.
Presentation on “Electric Industry Restructuring as if the Environment Mattered,” Boston Area Solar Energy Association, October 9, 1997.
Invited speaker on “Modeling Market Power in Electricity Generation,” National Association of Regulatory Utility Commissioners meeting in San Francisco, July 22, 1997.
Presentation on “Performance-Based Regulation in a Restructured Electric Industry,” National Association of Regulatory Utility Commissioners meeting in San Francisco, July 20, 1997.
Presentation on “State Initiatives and Regional Issues,” New England Governors’ Conference Workshop on Restructuring and Environmentally Sustainable Technologies, Warwick, Rhode Island, March 25, 1997.
Invited speaker on stranded costs, National Association of State Utility Consumer Advocates meeting in San Francisco, November 1996.
Presentation on “Nuclear Power Plant Decommissioning Costs and Electricity Restructuring,” Nuclear Decommissioning Trusts conference, New York City, November 18, 1996.
Invited speaker on stranded costs, Indiana Utilities Regulatory Commission Forum, Indianapolis, November 1, 1996.
Presentation on “Electric Industry Restructuring and the Environment,” at the Indiana Energy Conference, Indianapolis, Indiana, October 10, 1996.
Presentation on "Small Customers in a Restructured Electricity Industry: Transaction Costs, Advanced Metering Technologies and Aggregation Options" to the Consumers' Energy Conference, South Portland, Maine, July 1996.
Presentation on "Electric Generation Market Power in New England" to New England Conference of Public Utility Commissioners, Manchester Village, Vermont, May 1996.
Presentation on "Advanced Metering for Residential Customers on Electricity Restructuring" to National Consumer Law Center's 10th Annual Conference in Washington, DC, February 1996.
Presentations on "Market Power," "Environmental Aspects of Restructuring" and "Market Access for Small Customers" to Vermont Public Service Board workshops on electricity restructuring, January and February 1996.
Presentation on "Environmental Impacts of Energy: Sustainability and Social Costing" to British Columbia Utilities Commission Workshop, Vancouver, BC, March 1995.
Presentation on "Competition and Economic Efficiency" to the National Council on Competition and the Electric Industry, December 1995.
Presentation on "Compliance Planning Under Regulatory Uncertainty," to EPA "Opportunities Conference: Energy Efficiency and Renewable Energy," Washington, DC, June 1993.
Presentation on "Energy and Sustainability" to Hydro-Quebec Conference, Hampshire College, Amherst, Massachusetts, April 1993.
Invited Speaker on environmental externalities, ASME "ECO World" conference in Washington, DC, June 1992.
Invited Speaker, Association of Energy Engineers, Boston, Massachusetts, February 1992.
Presentation of Acid Rain Abatement Optimization Model to the Swedish Environmental Protection Agency, Solna, Sweden, November 1991.
Presentation on Integrated Resource Planning to Boston Gas Company, July 1990.
Training on Methods for Calculating Electric System Avoided Costs, provided to energy planners and policy makers from five Southeast Asian countries sponsored by U.S. Agency for

International Development and administered by the Institute of International Education, May 1990.
Invited Speaker, National Association of State Utility Consumer Advocates (NASUCA) Mid-Year Meeting, Annapolis, Maryland, and June 1988.
Invited Speaker, Conference on New Developments in Nuclear Decommissioning Costs and Funding Methods, sponsored by the Northeast Center for Professional Education, Washington, DC, April 1988.
Resume dated June 2010.

APPENDIX B

CONSIDERED DOCUMENTS

(1) Letter to Mr. William Presson (Michigan Department of Environmental Quality) from Kelly L. Guertin (DTE Energy Company), March 12, 2010.

(2) Letter to Mr. Mark Palermo (US EPA Region 5) from Michael J. Solo, Jr. (DTE Energy Company), June 3, 2010.

(3) Qualification and Direct Testimony of Sherrie L. Siefman (The Detroit Edison Company), MPSC Case No. U-16047, September 2009.

(4) Declaration of Ranajit (Ron) Sahu, in this matter.

Exhibit 9

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF INDIANA
INDIANAPOLIS DIVISION

UNITED STATES OF AMERICA, Plaintiff,	)	
STATE OF NEW YORK, STATE OF NEW JERSEY, STATE OF CONNECTICUT, HOOSIER ENVIRONMENTAL COUNCIL, and OHIO ENVIRONMENTAL COUNCIL, Plaintiff-Intervenors,	)	
vs.	)	1:99-cv-1693-LJM-JMS
PSI ENERGY, INC. and THE CINCINNATI GAS & ELECTRIC COMPANY, Defendants.	)	

FINAL JURY INSTRUCTIONS

INSTRUCTION NO. 1

Members of the jury, the evidence and arguments in this case have been completed, and I will now instruct you as to the law applicable to this case. It is your duty to follow all of the instructions.

You must not question any rule of law stated in these instructions. Regardless of any opinion you may have as to what the law ought to be, you must base your verdict upon the law as it is set out herein.

It is your duty to determine the facts from the evidence in this cause. You are to apply the law given to you in these instructions to the facts and in this way decide the case.

INSTRUCTION NO. 2

Unless you are otherwise instructed, the evidence in the case always consists of the sworn testimony of the witnesses, regardless of who may have called them; all exhibits received in evidence, regardless of who may have produced them; and all facts which may have been admitted or stipulated.

Any evidence to which an objection was sustained by the Court, and any evidence ordered stricken by the Court, must be entirely disregarded.

INSTRUCTION NO. 3

The burden is on the plaintiffs, and on the defendants for any affirmative defense, to prove every essential element of the case by a preponderance of all of the evidence. A preponderance of the evidence is evidence which, when considered and compared with that opposed to it, has more convincing force and produces in your minds a belief that what is sought to be proven is more likely true than not true. Your verdict may not be based on mere speculation.

If the proof fails to establish any essential element of plaintiffs' case by a preponderance of the evidence, or if the evidence on any essential element thereof is equally balanced, then you should find for the defendants.

I will hereafter use the phrase "if you find." Such phrase means "if you find from a preponderance of all the evidence," as just defined.

INSTRUCTION NO. 4

The law of this case is contained in these Instructions, considered as a whole. You are bound by your oath to follow the law.

Your job is to determine the facts. Do so without bias or prejudice against, or sympathy for, either party. All persons, individuals and corporations alike, stand equal before the law and are to be dealt with as equals in the court of justice. You therefore must consider this case as an action between persons of equal standing in the community, of equal worth, and holding similar stations in life.

INSTRUCTION NO. 5

You are the sole judges of the credibility -- that is, the believability -- of the witnesses. Reconcile their testimony on the theory that all are accurate and truthful, if you can; but if you cannot, then you must determine whom you will believe and whom you will not believe and what is the truth.

In determining the credibility of the witnesses, you may take into consideration their interest or lack of interest in the result of this suit; their manner and bearing on the witness stand; their means or lack of means of knowing the facts about which they have testified; how far, if at all, they are either supported or contradicted by other evidence; their power of memory or the lack thereof; inconsistent statements made by them, if any; and from all the evidence you will give to each witness the credit to which he or she is entitled.

Inconsistencies or discrepancies in the testimony of a witness, or between the testimony of different witnesses, may or may not cause the jury to discredit such testimony. Two or more persons witnessing an incident or a transaction may see or hear it differently; and innocent mis-recollection, like failure of recollection, is not an uncommon experience. In weighing the effect of any discrepancy, you may consider whether it pertains to a matter of importance or an unimportant detail, and whether the discrepancy results from innocent error or intentional falsehood.

INSTRUCTION NO. 6

The testimony of a witness may be discredited or impeached by contradictory evidence, or by proving that he or she previously made a statement inconsistent with his or her present testimony. Before you could consider a witness to have been impeached on the basis of an earlier contradictory statement, you would, of course, first have to find as a fact that such statement was indeed made by the witness and that it in fact contradicts his or her present testimony, considering all of the circumstances under which you find it to have been made.

If you believe any witness has been impeached, and thus discredited, or has knowingly testified falsely concerning any material matter, you have a right to distrust such witness's testimony in other particulars; and you may reject all the testimony of that witness or give such credibility as you may think it deserves.

INSTRUCTION NO. 7

The weight to be given to any particular evidence is not necessarily determined by the number of witnesses testifying on behalf of each side. You are to consider all the evidence in the case in determining the credibility of the witnesses. You may find that the testimony of a smaller number of witnesses for one side is more credible, and hence deserving of more weight, than the testimony of a greater number of witnesses for the other side.

INSTRUCTION NO. 8

There are, generally speaking, two types of evidence. One is direct evidence, such as the testimony of an eyewitness. The other is indirect or circumstantial evidence, that is, proof of a certain fact or facts from which you reasonably may deduce another fact. In other words, circumstantial evidence is that by which proof of one fact also tends to prove another, according to the common experience of mankind.

The law makes no distinction between the two, but simply requires that the jury find the facts in accordance with all the evidence, both direct and circumstantial.

INSTRUCTION NO. 9

You should use your common sense in weighing the evidence and consider the evidence in light of your own observations in life.

In our lives, we often look at one fact and conclude from it that another fact exists. In law we call this an "inference." A jury is allowed to make reasonable inferences. Any inferences you make must be reasonable and must be based on the evidence in the case.

INSTRUCTION NO. 10

Neither by these instructions, nor by any ruling or remark which I have made, do I mean to indicate any opinion as to the facts or as to what your verdict should be. You are the sole and exclusive judges of the facts.

INSTRUCTION NO. 11

The evidence from which you will find the facts consists of the testimony of witnesses, documents and other things received into the record as exhibits, and any facts the parties agree or stipulate to, or that the court may instruct you to find.

You are to consider only the evidence received in this case. You should consider this evidence in light of your own observations and experiences in life. You may draw such reasonable inferences as you believe to be justified from proven facts.

Certain things are not evidence and must not be considered by you. I will list them for you now:

1. Statements, arguments, and questions by counsel are not evidence.

2. Objections to questions are not evidence. The parties were entitled to make an objection when they believe evidence being offered is improper under the rules of evidence. You should not be influenced by the objection or by the Court's ruling on it. If the objection was sustained, ignore the question. If it was overruled, treat the answer like any other.

3. Testimony that the Court has excluded or told you to disregard is not evidence and must not be considered.

4. Anything you may have seen or heard outside the courtroom is not evidence and must be disregarded. You are to decide the case solely on the evidence presented here in the courtroom.

INSTRUCTION NO. 12

Certain demonstrative exhibits such as photographs and charts have been shown to you. Such demonstrative exhibits are used for convenience and to help explain the facts of the case. They are not themselves evidence.

INSTRUCTION NO. 13

The sworn testimony of several witnesses was taken by deposition prior to this trial. The testimony of a witness who for some proper reason cannot be present to testify in person may be presented in this form. Such testimony is given under oath and in the presence of the attorney for the parties, who question the witness. A stenographer records the testimony in a transcript so that you may later hear the questions asked and the answers given. Some of this sworn testimony was presented by reading the transcript to you; some of this sworn testimony was presented to you by videotape. You must consider this evidence in the same light and subject to the same tests that apply to testimony of other witnesses.

INSTRUCTION NO. 14

During the trial, you heard the testimony of expert witnesses. This testimony is admissible where the subject matter involved requires knowledge, special study, training, or skill not within ordinary experience, and the witness is qualified to give an expert opinion.

However, the fact that an expert has given an opinion does not mean that you are bound by the opinion, or that you are obligated to accept the opinion as to the facts. You should assess the weight to be given to the expert opinion in light of all the evidence in the case.

INSTRUCTION NO. 15

The law does not require any party to call as a witness every person who might have knowledge of the facts related to this trial. Similarly, the law does not require any party to present as exhibits all papers and things mentioned during this trial.

INSTRUCTION NO. 16

SUMMARY OF THE CLAIMS

This is a civil case brought by the plaintiffs, who are the United States; the States of New York, New Jersey, and Connecticut; and two groups representing local citizens, Hoosier Environmental Council and Ohio Environmental Council. Plaintiffs allege that the defendants, PSI Energy, Inc. and the Cincinnati Gas & Electric Company, violated the New Source Review program, or the "NSR program," of the Clean Air Act and similar programs under Indiana and Ohio state law. The Clean Air Act gives citizens and states the right to bring suit to enforce the provisions of the Act, which includes the New Source Review program.

In enacting the New Source Review program, Congress had several purposes in mind. Specifically, the stated purposes of the program are (1) "to protect public health and welfare from any actual or potential adverse effect . . . from air pollution"; (2) "to preserve, protect, and enhance the air quality" in national parks and similar areas of "national or regional natural, recreational, scenic, or historic value"; (3) "to [e]nsure that economic growth will occur in a manner consistent with the preservation of existing clean air resources"; (4) to assure that emissions from a source in one state do not interfere with a plan "to prevent significant deterioration of air quality" in another state; and (5) to assure that a decision to allow increased air pollution to occur in an area "is made only after careful evaluation of all the consequences of such a decision" and after an opportunity for public participation in the decisionmaking process. 42 U.S.C. § 7470.

INSTRUCTION NO. 16, continued

In order to achieve the goals of the New Source Review program, both the federal and state New Source Review programs require sources of air pollution, such as power plants, to obtain a permit and install pollution controls when plants are constructed or when they go through any changes that reasonably might be expected to increase emissions above certain prescribed limits. Such changes are known as major modifications.

In this case, Plaintiffs contend that Defendants violated both the federal and state New Source Review programs by failing to comply with the requirements pertaining to permits and pollution controls before undertaking several construction projects at five different power plants. The specific projects at issue are as follows:

Project #1:	Life extension project at Beckjord unit 1 from November 1987 to February 1988;
Project #2	Life extension project at Beckjord unit 2 from October 1987 to January 1988;
Project #3	Life extension project at Beckjord unit 3 from October 1985 to January 1986;
Project #4	Condensor retubing at Beckjord unit 5 from January 1991 to February 1991;
Proejct #5	Condensor retubing at Beckjord unit 6 from September 1994 to November 1994;
Project #6	Replacement of the pulverizers at Gallagher unit 1 from April 1998 to July 1998;

INSTRUCTION NO. 16, continued

Project #7	Condensor retubing at Gallagher unit 2 from August 1990 to December 1990;
Project #8	Replacement of the pulverizers at Gallagher unit 3 from February 1999 to April 1999;
Project #9	Replacement of the reheater tube section at Gibson unit 2 from February 2001 to May 2001;
Project #10	Replacement of the slope tubes and lower headers at Miami Fort unit 5, January 1995 to March 1995;
Project #11	Replacement of the front wall radiant superheater at Wabash River unit 2 from June 1989 to July 1989;
Project #12	Replacement of the high temperature finishing superheater tubes and upper reheater tubing assemblies at Wabash River unit 2 from May 1992 to September 1992;
Project #13	Replacement of the finishing, intermediate, and radiant superheater tubes and upper reheat tube bundles at Wabash River unit 3 from June 1989 to October 1989; and
Project #15	Replacement of the boiler pass and heat recovery actions at Wabash River unit 5 from February 1990 to May 1990.

INSTRUCTION NO. 17

MAJOR MODIFICATION

In this case, you must consider each project at issue and determine whether it is a major modification. The definition of a major modification has several components. The first and simplest definition is that a major modification is any physical change that increases the amount of air pollutant emitted above certain prescribed limits. The air pollutants involved in this case are sulfur dioxide and nitrogen oxides.

For each project, Plaintiffs have the burden of proving by a preponderance of the evidence that the project was a major modification. You must give separate consideration to each project in this case. In considering whether a project is a major modification, you must answer two questions that further define the term major modification:

1. Was there a physical change at a generating unit?
2. Should a reasonable power plant owner or operator have expected the physical change to result in a significant net increase in emissions, specifically for this case, an increase in either sulfur dioxide or nitrogen oxides?

Additional instructions for answering these two questions follow.

INSTRUCTION NO. 18

PHYSICAL CHANGE

The definition of a physical change is broad. There is no requirement that a project be a certain size or meet a certain cost threshold to be defined as a physical change. A physical change can consist of the repair and replacement of a single component, and can include the replacement of a piece of equipment with a new version of the same equipment. Certain activity, however, is excluded from the term physical change. Specifically, the activity that is excluded is known as routine maintenance, repair, and replacement, or "RMRR."

As a defense to the Plaintiffs' claims in this case, Defendants have alleged that some of their projects were routine maintenance, repair, and replacement activity and therefore not a physical change. It is Defendants' responsibility to prove that the projects qualify as routine maintenance, repair, and replacement. Therefore, you must find that a project was not routine maintenance, repair, and replacement unless Defendants prove by a preponderance of the evidence that a project qualifies as routine maintenance, repair, and replacement. If Defendants fail to satisfy that burden, you should conclude that a project does not qualify as routine maintenance, repair, and replacement activity and instead is a physical change. You should then proceed to the next question, whether a reasonable power plant owner or operator would have expected that physical change to result in a significant net increase in emissions.

On the other hand, if you find that Defendants have proved by a preponderance of the evidence that a particular project qualifies as routine maintenance, repair, and replacement, you must find Defendants not liable on that project.

INSTRUCTION NO. 19

ALLEGED ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT ACTIVITY

You will not have to decide the issue of physical change or RMRR activity for all projects. Instead, you will only have to consider that issue for the projects that Defendants allege were RMRR activity. Those projects are as follows:

Project #4	Condensor retubing at Beckjord unit 5 from January 1991 to February 1991;
Project #5	Condensor retubing at Beckjord unit 6 from September 1994 to November 1994;
Project #11	Replacement of the front wall radiant superheater at Wabash River unit 2 from June 1989 to July 1989;
Project #12	Replacement of the high temperature finishing superheater tubes and upper reheater tubing assemblies at Wabash River unit 2 from May 1992 to September 1992;
Project #13	Replacement of the finishing, intermediate, and radiant superheater tubes and upper reheat tube bundles at Wabash River unit 3 from June 1989 to October 1989; and
Project #15	Replacement of the boiler pass and heat recovery actions at Wabash River unit 5 from February 1990 to May 1990.

For each of the projects that Defendants have alleged involved RMRR activity, you must determine whether the particular project actually was RMRR activity.

INSTRUCTION NO. 20

ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT ANALYSIS

In making your determination on whether a project constitutes RMRR activity, you should keep in mind that the RMRR exclusion applies to a narrow range of activities. Further, in deciding whether a project is RMRR, you may consider:

- the nature of the project;
- the extent of the work performed;
- the purpose of the project;
- how frequently the project is performed at the facility;
- how frequently the type of project is performed within the industry at other facilities; and
- the cost of the project.

No single factor is dispositive. Instead, for each project, you should consider the circumstances as a whole when making your determination on whether the project was RMRR activity.

INSTRUCTION NO. 21

SIGNIFICANT NET EMISSIONS INCREASES

After you have completed your RMRR analysis for the six projects listed in Instruction No. 19, you must address a second question for any project that you decided was not RMRR and for the remaining projects for which Defendants have not asserted the RMRR defense. Specifically, you must determine whether a reasonable power plant owner or operator would have expected a project to result in a significant net increase in emissions. A significant net increase is one that would be expected to result in a net increase of an air pollutant of 40 or more tons per year.

In this case, the pollutants are sulfur dioxide and nitrogen oxides. In considering whether a reasonable power plant owner or operator would have expected a project to result in a significant net increase in emissions, you must evaluate each of these pollutants individually at each project under consideration.

If a project was not RMRR and you conclude that a reasonable owner or operator should have expected a project to result in a significant net increase of 40 or more tons per year in sulfur dioxide or nitrogen oxides emissions, you should find that the project was a major modification and, consequently, your verdict should be for Plaintiffs.

If, on the other hand, a project was not RMRR and you conclude that a reasonable owner or operator should not have expected a project to result in a significant net increase of 40 or more tons per year in sulfur dioxide or nitrogen oxides emissions, you should find that the project was not a major modification and, consequently, your verdict should be for Defendants.

INSTRUCTION NO. 22

PROJECTS REQUIRING AN EMISSIONS DETERMINATION

You must make a determination on significant net emissions increases for each of the projects that you concluded was not RMRR and for each of the following projects:

Project #1	Life extension project at Beckjord unit 1 from November 1987 to February 1988;
Project #2	Life extension project at Beckjord unit 2 from October 1987 to January 1988;
Project #3	Life extension project at Beckjord unit 3 from October 1985 to January 1986;
Project #6	Replacement of the pulverizers at Gallagher unit 1 from April 1998 to July 1998;
Project #7	Condensor retubing at Gallagher unit 2 from August 1990 to December 1990;
Project #8	Replacement of the pulverizers at Gallagher unit 3 from February 1999 to April 1999;
Project #9	Replacement of the reheater tube section at Gibson unit 2 from February 2001 to May 2001; and
Project #10	Replacement of the slope tubes and lower headers at Miami Fort unit 5, January 1995 to March 1995.

INSTRUCTION NO. 23

ANALYSIS FOR SIGNIFICANT NET EMISSIONS INCREASES

Your consideration of whether a reasonable owner or operator should have expected a project to result in a significant net increase in emissions is not dependent upon whether emissions actually increased after a project. The law requires an owner or operator to make an assessment or prediction on that question before the project begins. Therefore, you must look to the information available to Defendants at the time that they began a project and decide whether a reasonable owner or operator should have predicted that a project would have caused a net increase of 40 or more tons per year in sulfur dioxide or nitrogen oxide emissions. You should consider all relevant information available to Defendants at the time of the project, including prior operating data and Defendants' own statements and documents.

In making your determination, you should compare the emissions per year before a project began to the emissions predicted to result from the project. To do so, you must look at a reasonable baseline period which is representative of normal operations before a project was performed. In this case, for projects started before July 21, 1992, the proper baseline period is the 24 months immediately prior to the start of the project. For projects that started after July 21, 1992, the proper baseline period can be any 24-month period within the 5 years preceding the project as long as you are comfortable that the period is representative of the normal operation of a unit during those 5 years.

INSTRUCTION NO. 23, continued

As a final matter, in making your determination you should exclude from your consideration a change in emissions that is unrelated to a physical change, that is, to the project itself. For instance, an increase that is unrelated to a physical change and instead is attributable to a growth in demand for electricity should be excluded. Such an exclusion is sometimes referred to as the "demand growth exclusion." The demand growth exclusion applies to emissions increases that could have been predicted or projected regardless of whether a physical change was to occur.

The burden is on Defendants to prove by a preponderance of the evidence that the demand growth exclusion applies to an emissions increase. In doing so, Defendants must demonstrate that the following two factors apply to the increase:

1. the unit could have accommodated the increase in emissions before the physical change; and
2. the increase is unrelated to the physical change.

INSTRUCTION NO. 24

Your job as jurors in this case is to decide whether Defendants are liable for the claims asserted against them. Include in your consideration whether Defendants, in fact, complied with the law, not whether they intended to comply. In deciding whether Defendants are liable, you should not be concerned about the question of damages or whether any harm may have resulted from the alleged violations; that is the Court's role after you have reached a decision on liability. You should only concern yourselves with deciding whether the RMRR exclusion has been met for those projects for which Defendants have asserted this defense and whether significant net emissions increases were likely to result from the Defendants' projects as those questions have been outlined for you.

INSTRUCTION NO. 25

During this trial I permitted you to take notes. Many courts do not permit note-taking by jurors, and a word of caution is in order. There is always a tendency to attach undue importance to matters that one has written down. Some testimony that is considered unimportant at the time presented, and thus not written down, takes on greater importance later in the trial in light of all the evidence presented. Therefore, you are instructed that your notes are only a tool to aid your own individual memory and you should not compare your notes with those of other jurors in determining the content of any testimony or in evaluating the importance of any evidence. Your notes are not evidence, and are by no means a complete outline of the proceedings or a list of the highlights of the trial. Above all, your memory should be your greatest asset when it comes time to deliberate and render a decision in this case.

If you did takes notes, you must leave your notes in the jury room after your verdict has been returned.

INSTRUCTION NO. 26

It is necessary from this time until you are discharged to remain together in a group and in the charge of the Bailiff. You are not, during your deliberations, to talk with anyone, other than your fellow jurors and the Bailiff. Make known to him or her any of your wants, and if you wish to communicate with me place your questions in writing and the Bailiff will contact me if necessary.

When you go to the jury room, elect one of your number as foreperson. It is the duty of the foreperson to see that your discussions are orderly and that each juror has the opportunity to discuss and vote on each matter before you. The authority of the foreperson is otherwise the same as that of any other juror.

These Instructions are all in writing and I will send them to the jury room for your use in your deliberations upon your verdict. You will also be permitted to take the exhibits with you for your use in your deliberations. When you have arrived at your verdict, have the foreperson sign and date it and notify the Bailiff in whose charge you have been placed.

INSTRUCTION NO. 27

I do not anticipate that you will need to communicate with me. If you do, however, the only proper way is in writing, signed by the foreperson, or if he or she is unwilling to do so, by some other juror, and given to the Bailiff and he or she will communicate with me.

INSTRUCTION NO. 28

A Special Verdict Form has been prepared for you. You should fill out the Special Verdict Form as part of your deliberations.

(Special Verdict Form read)

In addition, a verdict form has been prepared for you.

(Verdict Form read)

Take these forms to the jury room and, when you have reached unanimous agreement on the verdicts, your foreperson will fill in, date and sign the forms and return the completed forms with you into open Court.

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF INDIANA
INDIANAPOLIS DIVISION

UNITED STATES OF AMERICA, Plaintiff,	)	
STATE OF NEW YORK, STATE OF NEW JERSEY, STATE OF CONNECTICUT, HOOSIER ENVIRONMENTAL COUNCIL, and OHIO ENVIRONMENTAL COUNCIL, Plaintiff-Intervenors,	)	
vs.	)	1:99-cv-1693-LJM-JMS
PSI ENERGY, INC. and THE CINCINNATI GAS & ELECTRIC COMPANY, Defendants.	)	

SPECIAL VERDICT FORM

PROJECTS FOR WHICH DEFENDANTS ASSERT A ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT DEFENSE

1. Project #4: Condensor retubing at Beckjord unit 5 from January 1991 to February 1991;

   a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity?

   ____ YES ____ NO

   If you answered yes, return a verdict for Defendants on this project on the Verdict Form and proceed to the next project. If you answered no, then proceed to questions 1.b. and 1.c. below.

b. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

____ YES ____ NO

c. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?

____ YES ____ NO

If you answered yes to either question 1.b. or 1.c., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 1.b. and 1.c., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

2. Project #5: Condensor retubing at Beckjord unit 6 from September 1994 to November 1994;

a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity?

____ YES ____ NO

If you answered yes, return a verdict for Defendants on this project on the Verdict Form and proceed to the next project. If you answered no, then proceed to question 2.b. below.

b. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

____ YES ____ NO

If you answered yes to question 2.b., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered

no to questions 2.b., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

3. Project #11: Replacement of the front wall radiant superheater at Wabash River unit 2 from June 1989 to July 1989;

   a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity?

      ____ YES ____ NO

   If you answered yes, return a verdict for Defendants on this project on the Verdict Form and proceed to the next project. If you answered no, then proceed to questions 3.b. and 3.c. below.

   b. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

      ____ YES ____ NO

   c. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?

      ____ YES ____ NO

   If you answered yes to either question 3.b. or 3.c., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 3.b. and 3.c., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

4. Project #12: Replacement of the high temperature finishing superheater tubes and upper reheater tubing assemblies at Wabash River unit 2 from May 1992 to September 1992;

   a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity?

      ____ YES ____ NO

   If you answered yes, return a verdict for Defendants on this project on the Verdict Form and proceed to the next project. If you answered no, then proceed to question 4.b. below.

   b. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

      ____ YES ____ NO

   If you answered yes to question 4.b., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to question 4.b., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

5. Project #13: Replacement of the finishing, intermediate, and radiant superheater tubes and upper reheat tube bundles at Wabash River unit 3 from June 1989 to October 1989;

   a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity?

      ____ YES ____ NO

   If you answered yes, return a verdict for Defendants on this project on the Verdict Form and proceed to the next project. If you answered no, then proceed to questions 5.b. and 5.c. below.

   b. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

      ____ YES ____ NO

c. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?

____ YES ____ NO

If you answered yes to either question 5.b. or 5.c., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 5.b. and 5.c., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

6. Project #15: Replacement of the boiler pass and heat recovery actions at Wabash River unit 5 from February 1990 to May 1990;

a. Did Defendants prove by a preponderance of the evidence that the project qualified as RMRR activity?

____ YES ____ NO

If you answered yes, return a verdict for Defendants on this project on the Verdict Form and proceed to the next section. If you answered no, then proceed to questions 6.b. and 6.c. below.

b. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

____ YES ____ NO

c. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?

____ YES ____ NO

If you answered yes to either question 6.b. or 6.c., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next section. If you answered no to both questions 6.b. and 6.c., return a verdict for Defendants on this project on the Verdict Form and proceed to the next section.

REMAINING PROJECTS

7. Project #1: Life extension project at Beckjord unit 1 from November 1987 to February 1988;

   a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

      ____ YES ____ NO

   b. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?

      ____ YES ____ NO

   If you answered yes to either question 7.a. or 7.b., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 7.a. and 7.b., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

8. Project #2: Life extension project at Beckjord unit 2 from October 1987 to January 1988;

   a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

      ____ YES ____ NO

   b. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?

____ YES ____ NO

If you answered yes to either question 8.a. or 8.b., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 8.a. and 8.b., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

9. Project #3: Life extension project at Beckjord unit 3 from October 1985 to January 1986;

   a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

   ____ YES ____ NO

   b. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in nitrogen oxides emissions of 40 tons or more per year as a result of the project?

   ____ YES ____ NO

If you answered yes to either question 9.a. or 9.b., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 9.a. and 9.b., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

10. Project # 6: Replacement of the pulverizers at Gallagher unit 1 from April 1998 to July 1998;

   a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

   ____ YES ____ NO

If you answered yes to question 10.a., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered

no to both questions 10.a., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

11. Project #7: Condensor retubing at Gallagher unit 2 from August 1990 to December 1990;

    a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

    ____ YES ____ NO

    If you answered yes to question 11.a., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 11.a., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

12. Project # 8: Replacement of the pulverizers at Gallagher unit 3 from February 1999 to April 1999;

    a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

    ____ YES ____ NO

    If you answered yes to question 12.a., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to question 12.a., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

13. Project #9: Replacement of the reheater tube section at Gibson unit 2 from February 2001 to May 2001;

    a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

    ____ YES ____ NO

If you answered yes to question 13.a., return a verdict for Plaintiffs on this project on the Verdict Form and proceed to the next project. If you answered no to both questions 13.a., return a verdict for Defendants on this project on the Verdict Form and proceed to the next project.

14. Project # 10: Replacement of the slope tubes and lower headers at Miami Fort unit 5, January 1995 to March 1995;

    a. After considering any demand growth exclusion that you find Defendants have proven by a preponderance of the evidence for this project, did Plaintiffs prove by a preponderance of the evidence that a reasonable power plant owner or operator would have expected a net increase in sulfur dioxide emissions of 40 tons or more per year as a result of the project?

    ____ YES ____ NO

    If you answered yes to question 14.a., return a verdict for Plaintiffs on this project on the Verdict Form. If you answered no to both question 14.a., return a verdict for Defendants on this project on the Verdict Form.

Once you have completed all of the questions on this Special Verdict Form and filled out the Verdict Form, sign and date both this Special Verdict Form and the Verdict Form and inform the Bailiff that you have reached a verdict.

_____ _____

FOREPERSON Date

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF INDIANA
INDIANAPOLIS DIVISION

UNITED STATES OF AMERICA, Plaintiff,	)	
STATE OF NEW YORK, STATE OF NEW JERSEY, STATE OF CONNECTICUT, HOOSIER ENVIRONMENTAL COUNCIL, and OHIO ENVIRONMENTAL COUNCIL, Plaintiff-Intervenors,	)	
vs.	)	1:99-cv-1693-LJM-JMS
PSI ENERGY, INC. and THE CINCINNATI GAS & ELECTRIC COMPANY, Defendants.	)	

VERDICT FORM

We, the Jury in the above-entitled action, unanimously find in favor of:

PROJECTS FOR WHICH DEFENDANTS ASSERT A ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT DEFENSE

____ Plaintiffs	____ Defendants	on Project #4, the condensor retubing project at Beckjord unit 5 from January 1991 to February 1991;
____ Plaintiffs	____ Defendants	on Project #5, the condensor retubing project at Beckjord unit 6 from September 1994 to November 1994;
____ Plaintiffs	____ Defendants	on Project #11, the front wall radiant superheater replacement project at Wabash River unit 2 from June 1989 to July 1989;

_____ Plaintiffs	_____ Defendants	on Project #12, the high temperature finishing superheater tubes and upper reheater tubing assemblies replacement project at Wabash River unit 2 from May 1992 to September 1992;
_____ Plaintiffs	_____ Defendants	on Project #13, the finishing, intermediate, and radiant superheater tubes and upper reheat tube bundles replacement project at Wabash River unit 3 from June 1989 to October 1989;
_____ Plaintiffs	_____ Defendants	on Project #15, the boiler pass and heat recovery actions replacement project at Wabash River unit 5 from February 1990 to May 1990;

REMAINING PROJECTS

_____ Plaintiffs	_____ Defendants	on Project #1, the life extension project at Beckjord unit 1 from November 1987 to February 1988;
_____ Plaintiffs	_____ Defendants	on Project #2, the life extension project at Beckjord unit 2 from October 1987 to January 1988;
_____ Plaintiffs	_____ Defendants	on Project #3, the life extension project at Beckjord unit 3 from October 1985 to January 1986;
_____ Plaintiffs	_____ Defendants	on Project #6, the pulverizers replacement project at Gallagher unit 1 from April 1998 to July 1998;
_____ Plaintiffs	_____ Defendants	on Project #7, the condensor retubing project at Gallagher unit 2 from August 1990 to December 1990;
_____ Plaintiffs	_____ Defendants	on Project #8, the pulverizers replacement project at Gallagher unit 3 from February 1999 to April 1999;
_____ Plaintiffs	_____ Defendants	on Project #9, the reheater tube section replacement project at Gibson unit 2 from February 2001 to May 2001; and
_____ Plaintiffs	_____ Defendants	on Project #10, the slope tubes and lower headers replacement project at

Miami Fort unit 5, January 1995 to March 1995.

FOREPERSON

Date

Exhibit 10

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	)	
	)	
	)	
Plaintiff,	)	Civil Action No.
	)	
v.	)	
	)	
DTE ENERGY COMPANY, and	)	
DETROIT EDISON COMPANY	)	
	)	
	)	
Defendants.	)	
	)	

DECLARATION OF
MYRON ADAMS

(1) I, Myron Adams, was employed for over forty years by American Electric Power (AEP) Service Corporation, the management and technical arm of the AEP System, one of the largest electric utilities in the world. Virtually my entire career with AEP was spent in the area of resource planning, in both technical and management roles. I spent many years as AEP's director of Integrated Resource Planning, before assuming a transition position (demand side management consultant), within Integrated Resource Planning, prior to retiring from AEP. Since retiring from AEP, I have served as an independent consultant in the resource planning technical area.

(2) I have a B.S. in electrical engineering and an M.S. in management from the Massachusetts Institute of Technology.

(3) I have experience in all areas of Generation and Integrated Resource Planning, including: analysis of system resource requirements; planning for additional supply-side and/or demand-side resources; analysis of generating system reliability, including effects of individual generating units thereon; analysis of operation of generating resource system, including

individual generating units therein; projected operating levels of generating units, associated fuel requirements, and projected emissions; projected generating unit operating lifetimes and related issues; engineering economics and cost/benefit analysis; in cooperation with Company engineering personnel, analysis of potential major generating unit projects and the system effects thereof; load forecasting and related economic analysis.

(4) This declaration contains my opinions, conclusions, and the reasons therefore on the subjects that I was asked to address. I am being compensated for my work on this declaration and for any testimony at the rate of $150 per hour. The documents I considered are set forth in Appendix A.

(5) The following discussion is based primarily on my experience with AEP, but, I believe, based on industry literature I have read over the course of my career, and on my interactions with resource planners at other utilities, the discussion applies more generally, as well.

(6) Resource Planning (or Generation Planning) involves analyses of the current and projected operation of an electric utility's generating units, sometimes within an overall integrated generation or power system context, and sometimes on an individual generating unit basis. The areas covered include, among others, reliability analyses, generation, fuel and emission projections, production cost studies, and cost/benefit analyses. Projections of individual unit and aggregate system generation levels and fuel requirements, together with their associated costs and other parameters of interest, are virtually an everyday activity for resource planners, and are undertaken in connection with analyzing a variety of "problems" within their areas of responsibility. Such problems may include, among others, determining the most appropriate resource alternative for meeting any additional system resource requirements, and analyses related to individual power plant projects. They are also frequently responsible for projections of

individual generating unit and aggregate system generation, fuel requirements, and emissions for various purposes.

(7) In connection with their technical responsibilities, resource planners routinely interact with a variety of company groups, including what I will term "power plant" engineers and analysts, by which I mean the Mechanical, Civil, Electrical, Environmental, and other engineers and analysts whose primary areas of responsibility relate to power plants and their internal systems (boilers, turbines, generators and electrical equipment, etc.), as well as maintenance planning, fuel supply planning, nuclear and hydro generating units, etc. Interactions between resource planners and power plant engineers work both ways. The power plant engineers and analysts provide resource planners with certain technical assumptions required for their analyses, and with an overall understanding of the concepts and considerations involved in the various power plant engineering areas of responsibility. Likewise, resource planners may carry out cost/benefit analyses in power plant engineering areas (i.e., related to individual generating units), or provide "system" inputs and guidance to power plant engineers and analysts in carrying out such analyses themselves.

(8) Of interest in the area of power plant project analysis is the resource planner's familiarity with the current and projected operation of the system's generating units within the overall system context (e.g., projected energy production cost, rank within the system generation "loading order", etc.), and with projected overall system energy production and capacity costs. Resource planners are familiar with these factors because these are some of the output values from system production cost and other analyses for which they are responsible, and carry out on a regular basis. These factors are key input parameters into various analyses, as they provide the basis for

estimating the "system" benefits (or costs) of a particular alternative under scrutiny, such as a particular resource alternative or a power plant improvement project.

(9) Replacing or carrying out major refurbishment on a sizeable generating unit component or subsystem, such as an economizer or reheater component, can be expected to improve the availability of that component or subsystem. This, in turn, can be expected to improve the availability of the affected generating unit. Power plant engineers have been making estimates of such effects of component performance on total unit performance for at least a century. The effect of improved availability on unit generation arises from the fact that there were/would be expected to be times when the impaired component/subsystem would have kept the unit from being able to operate, while the replaced/improved component is expected to allow operation. This leads directly to an increase in expected dispatched (actual) generation (and associated fuel consumption and emissions) during the formerly impaired periods.

(10) When analyzing the effects of a single project at a single generating unit, the most appropriate focus is just that, namely a single project / single unit focus. Interactions between the affected unit and the rest of the system are important, but these are generally modeled through the use of unit utilization factors and system avoided costs.

(11) While a single project / single unit focus is most appropriate for project analyses such as the one at issue, a full system analysis, if performed, would lead to similar conclusions, namely, that if you improve a unit's forced outage rate or availability, greater generation (and therefore emissions) for that unit would result. Such analyses employ full system production cost models such as PROMOD, used by DTE and extensively by AEP under my direction.

(12) It should be noted that a generating unit already exhibiting a high level of utilization, i.e., a high capacity factor, can experience an availability increase and related increased generation at least

as much as any other unit. Such a unit generally exhibits a high capacity factor because it is among the system's most economical units to operate, and thus should operate at a high level during the additional time that any availability improvement makes it available.

(13) The economic value of increased availability arises directly from that increased generation and the unit's low operating costs. It reflects the system savings from supplying the increased generation from the unit in question versus supplying the same amount of energy from other system sources.

(14) The system economic benefits of this increased generation generally constitute the majority of the benefits in such a project's economic analysis underlying management's decision to implement it.

(15) These conclusions are borne out in the testimony of Mr. Paul Fessler before the Michigan Public Service Commission (PSC) in DTE's January 2009 rate case filing, Case No. U-15768. Mr. Fessler is the Vice President of Fossil Operations for the Detroit Edison Company. Mr. Fessler testified in detail about how Detroit Edison fleet of coal-fired plants "has experienced and continues to experience operational reliability issues on major system components that need to be addressed through on-going O&M and capital improvements." [p. PF9]. These investments in improving unit availability include about $40 million on replacing major components of Monroe Unit 2 in order to improve the unit's availability. These substantial investments in availability improvements would not be prudent unless DTE anticipated that this additional availability would be utilized, manifesting itself in increased generation and, consequently, emissions.

I declare under penalty of perjury that the foregoing is true and correct.

Myron Adams

Myron Adams

Executed on July 26, 2010 in Columbus, Ohio

APPENDIX A

CONSIDERED DOCUMENTS

(1) Letter to Mr. William Presson (Michigan Department of Environmental Quality) from Kelly L. Guertin (DTE Energy Company), March 12, 2010.

(2) "Extreme Makeover: Power Plant Edition," Monroe Evening News, April 22, 2010.

(3) Qualifications and Direct Testimony of Paul Fessler (The Detroit Edison Company), MPSC Case No. U-15768, January 2009.

Exhibit 11

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	)
	)
	)
Plaintiff,	)
	)
v.	)
	)
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY	)
	)
	)
	)
Defendants.	)
	)

DECLARATION OF
MATTHEW I. KAHAL

(1) My name is Matthew I. Kahal. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. I am employed as an independent consulting economist specializing in energy economics, public utility regulation and financial analysis. I have more than 30 years of experience related to public utilities regulation and policies and electric utility planning. My work has focused on utility mergers and acquisitions, power plant certification, contracting for purchased power, financing/cost of capital assessments and resource planning. I have testified on these (and other) issues before state and federal regulatory commissions, the United States Congress, state and federal courts and state legislatures on more than 350 occasions. Please see attached as Appendix A a detailed statement of my qualifications and a listing of past testimonies.

(2) I hold BA and MA degrees in economics and completed all course work and qualifying examination requirements for the Ph.D. from the University of Maryland. In 1981,

I became a founding principal of the consulting firm, Exeter Associates, Inc., where I served as Vice President and President, leaving in 2001. Prior to founding Exeter Associates, I was employed as an economist with a Washington, D. C. consulting firm (J. W. Wilson & Associates) and the Aerospace Corporation. I also held part-time faculty positions in economics and business at the University of Maryland and Montgomery College.

(3) I have been asked to examine certain issues related to Unit 2 at the Monroe Power Plant owned by the Detroit Edison Company ("Detroit Edison" or "the Company"). The Company has recently completed certain major capital projects at Unit 2 that were initiated in mid-March 2010 and were expected to be completed in June 2010. (Letter to Mr. William Presson, March 12, 2010)

(4) The projects include replacement of economizer tubes and reheat pendants, replacement of water wall tubes; extensive turbine system repairs and equipment replacement; electrical system repairs; and replacement of air heater gas side expansion joints. (Id., Attachment A). Some of the repairs and equipment replacements at Monroe Unit 2 were identified in the 2009 rate case testimony of Detroit Edison witness Fessler who referenced them as "major capital projects." (Direct Testimony, page 26, MPSC Case No. U-15768)

Background

(5) Detroit Edison is the electric utility company that serves most of Michigan's electric power demands. It is a wholly-owned subsidiary of DTE Energy, which is a diversified energy company. The Company accounts for about two-thirds of DTE's earnings and is

its largest subsidiary by a range of measures. DTE Energy also owns a major gas utility (Mich Con) and several unregulated subsidiaries. Detroit Edison owns over 11,000 MW of installed generating capacity to serve its Michigan customers and sells nearly 50 million MWh of electricity supply annually. (Detroit Edison, SEC Form 10-K for 2009)

(6) Detroit Edison is a predominantly coal-fired utility, although it also has significant amounts of nuclear generation. Company witness Fessler reports that in recent years 83 percent of the Company's generation is from its coal-fired power plants. (Direct Testimony, page 9) The Monroe power plant has four units and is Detroit Edison's largest, with a total of over 3,100 MW of rated capacity. Unit 2 is 795 MW nominal capacity or about one quarter of the power plant station total. In 2009, the Monroe power plant operated at about a 70 percent capacity factor, which would imply generation at Unit 2 of about 5 million MWh per year. The operating cost of the Monroe station in 2009 was about 2.6 cents per Kwh, with a cost of fuel of 2.1 cents per Kwh. (2009 Annual Report submitted to the Michigan Public Service Commission, April 2010, page 402) Unit 2 represents about 7 percent of Detroit Edison's installed capacity and, as a base load unit, it provides about 10 percent of the Company's generation supply.

(7) Detroit Edison is a very large, financially sound utility. In 2009, it earned $376 million and owned $16 billion in assets. The Company anticipates that its earnings will continue to increase over time. In 2009, cash flow from operations was $1.2 billion with a dividend payment to its parent (i.e., DTE Energy) of $305 million. Cash flows from operations exceeded capital spending in both 2008 and 2009, and it would be reasonable to expect this trend to continue. (Detroit Edison SEC From 10-K, pages 21-24 and DTE Energy April 2010 presentation to securities analysts)

(8) In addition to Detroit Edison's very strong earnings and cash flow performance in 2009, it maintains a strong balance sheet with approximately 50 percent common equity. Its long-term debt is rated medium to low single A by the major credit rating agencies. (*Id.*) Detroit Edison's retail operations are regulated by the Michigan Public Service Commission (MPSC) and at wholesale by the Federal Energy Regulatory Commission (FERC). The vast majority of the Company's operations and sales are at retail. The Company is a member of the Midwest Independent System Operator ("MISO") which is a FERC-approved Regional Transmission Organization ("RTO") that operates the regional transmission grid, along with associated markets for "spot" electric energy (and certain ancillary services).

Detroit Edison System Demand

(9) As directed by the MPSC in Case No. U-16160, Detroit Edison submitted its 2010 reliability assessment in March 2010 (*Summer 2010 Resource Adequacy Plan*, March 31, 2010). Detroit Edison projects its Summer 2010 load requirement for both its total load and its "bundled load," with and without interruptible load. The Company plans for generation reliability for its "bundled load" after subtracting out interruptible load. Michigan is "a retail access state" meaning that Detroit Edison retail customers can select a competitive supplier over their local utility for generation supply (though not for delivery service). "Bundled service" refers to retail load that stays with Detroit Edison for generation supply, i.e., more than 90 percent of the total load at present. Detroit Edison notes that both total and bundled load have fallen sharply in the last five years, i.e., a decline since 2006 of about 1,500 MW (nearly 15 percent). The Company's 2010 reliability report finds that its installed generating capacity will be adequate to meet

MISO reserve margin targets in all months of 2010 except July. The Company intends to meet the July 2010 reserve target through short-term (i.e., Summer 2010) capacity purchases from the wholesale capacity market. There is ample capacity available for purchase. A similar observation was made by the *Michigan Energy Appraisal* recently published by the Michigan Department of Energy, Labor & Economic Growth and the MPSC (available on the MPSC web site). Referring to the reported MISO surplus, the report states "This year's abundant [MISO] reserves mean that plenty of additional resources should be available if demand in Michigan is higher than expected." (Page 3)

(10) The Detroit Edison analysis and the strategy of short-term capacity purchases refers to 2010. However, the surplus is likely to persist for several years due to expectations of sluggish growth and investments in energy efficiency and renewable resources, mandated by law or regulation.

(11) The Company's long-term load forecast for bundled load and total load is provided in the 2009 Power Supply Cost Recovery testimony of Sherrie L. Siefman. (MPSC Case No. U-16047) This forecast is part of the same Company analysis that Detroit Edison presented to the Michigan Public Service Commission in September 2009 and relied on in its March 12, 2010 letter to the state New Source Review permitting authority. The Company's total supply requirement (including line losses) in thousands of MWh is shown below for the historical and forecast period:

2003	55,800
2004	55,656
2005	58,117
2006	57,348
2007	58,128
2008	55,703
2009	51,041
2010	51,387
2011	51,763
2012	52,224
2013	52,331
2014	52,069
(Source: Exhibit A-8)	

This shows a substantial decline in energy requirements in the forecast period compared to the recent actuals. (The forecast actually begins in 2009.) The Company's notification letter concerning the modifications at Monroe Unit 2 state that the "new baseline for that plant was May 2005-April 2007." As noted above, annualized System energy requirements during that period were roughly 58 million MWh, compared with a forecast going forward of 51 to 52 million Mwh, i.e., an outlook of declining demand compared to this baseline period. The Company has also selected new baseline periods of June 2006-June 2008 for SO_2, October 2006-September 2008 for NO_x and January 2008-December 2009 for particulates. While the actual System power demands are not readily available to me for the historic periods, the Company's own outlook nonetheless is an overall downward trend in power demands for the next five years compared to the last five years and a downward trend in comparing the Company's selected baselines to its projection period. The demand projected for the year 2013 is lower than each calendar year used by the Company in any of its baselines. While the Company is correct that there are a number of factors that can affect the actual operation of a generating unit (including the

behavior of the MISO market), Detroit Edison's modeling results presented to state regulators are not consistent with its claim that any increase in generation at Monroe Unit 2 is the result of demand growth. As noted, the recent historical and forecasted trend in power demands is downward or stagnant, while in the same modeling analysis the Company expects Monroe Unit 2 generation to increase.

The Operation of Monroe Unit 2

(12) I reviewed the Company's June 1, 2010 letter, in which the Company asserted that a change in the price of natural gas would result in less demand for Monroe Unit 2. It is true that the price of natural gas and price outlook today are lower than in the 2007/2008 timeframe, though not necessarily as compared to 2009. However, natural gas remains a premium boiler fuel in terms of cost. The Monroe Unit 2, as a coal-fired unit, has a very low fuel or "running" cost. Generating units are dispatched and committed to serve load based on their running costs, i.e., the lowest cost units first, followed successively by the more expensive-to-operate units until all electrical demand is served. At the current and expected natural gas prices, (i.e., $4 to $6 per mmbtu), the low-cost Monroe Unit 2 would be dispatched before the more expensive-to-operate gas-fired units. Thus, it is difficult to accept the Company's assertion that the observed and expected moderation in natural gas prices by itself would cause Monroe Unit 2 to operate less. As an efficient, coal-fired unit, Monroe Unit 2 is considered to be a "baseload" resource. This means that due to its low and stable cost of fuel per kwh it will operate in the vast majority of hours of the year that it is available for service. An important implication is that if the availability of the baseload unit is improved (i.e., fewer days or weeks of outage downtime), the baseload

unit can be expected to increase its total operation and thereby increase its amount of electric generation supply.

(13) Internal Company documents provide information on the costs, purpose and investment attributes of the Monroe Unit 2 project.[1] The planned expenditure on this project is quite large, estimated to be in excess of $60 million, primarily being major capital expenditures. The Company's financial model treats this as a regulated investment that will provide a stream of cash flow and net income for Company shareholders over a period of many years. Large components of the project (e.g., the economizer and reheater) are being undertaken due to concerns over corrosion of the boiler. By undertaking these capital improvements, the project is intended to reduce forced outages and therefore downtime at the unit. Since Monroe Unit 2 is a low-cost baseload plant that typically operates when available for service, significantly reducing forced outages at the unit can be expected to result in increased operation and generation as compared to not undertaking this major capital project.

Potential Emissions Reductions

(14) The Plaintiff has identified certain measures at Detroit Edison's Belle River and Trenton Channel power plants that could reduce emissions of NO_x and SO_2. According to Plaintiff's witness Dr. Ron Sahu, a preliminary and proximate cost estimate for such controls would be a capital investment of about $39 million and annual expense on the order of about $14 million. The $39 million capital investment would likely translate into a levelized annual capital investment of about $5 million (assuming a capital

[1] These company documents were provided in response to a request made by EPA during the EPA inspection of Monroe Unit 2, and are attached to the Declaration of Ethan Chatfield.

recovery factor of about 12 percent), implying a total cost recovery of about $19 million per year.

(15) The estimated $39 million capital expenditure would not be in any way financially problematic for Detroit Edison. This investment compares with year-end 2009 assets of $16 billion, annual capital expenditures in recent years of about $800 million and annual operating cash flow in excess of $1 billion. (SEC Form 1 for 2009, pages 23-24). This outlay would be a minor change to the Company's capital budget and can easily be financed. This would not materially impact the Company's financial position or credit quality.

(16) Presumably, such costs (if deemed prudently-incurred) would become eligible for recovery from utility customers. While rate increases, no matter how small, are never welcome, the annualized cost recovery of about $19 million would have only a modest effect on customer bills, given Detroit Edison's large size. For example, Detroit Edison's 2009 electric operating revenue was $4.7 billion. (Id., page 21) Thus, if $19 million per year cost recovery is approved by the MPSC as part of a future rate case, the customer rate increase impact would be about 0.4 percent.

(17) This declaration contains my opinions, conclusions, and the reasons therefore on the subjects that I was asked to address. The body of the declaration and appendices list the data and other information considered in forming these opinions. Exhibit and tables in summary of, or support of, these opinions are included with this declaration. Appendix A provides a statement of my qualifications. Appendix A also includes a listing of publications during the past ten years and a listing of cases in which I have testified as an

expert. Appendix B provides a list of considered documents. I am being compensated for my time in the preparation of this declaration and any testimony at the rate of $135 per hour.

I declare under penalty of perjury that the foregoing is true and correct.

Matthew I. Kahal

Executed on August 2, 2010 in Columbia, Maryland

APPENDIX A

STATEMENT OF QUALIFICATIONS OF

MATTHEW I. KAHAL

MATTHEW I. KAHAL

Mr. Kahal is currently an independent consulting economist, specializing in energy economics, public utility regulation and financial analysis. Over the past two decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing and a wide range of utility financial issues. In the financial area he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone and water utilities. Mr. Kahal's work in recent years has shifted to electric utility restructuring, mergers and competition.

Mr. Kahal has provided expert testimony on more than 300 occasions before state and federal regulatory commissions and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring and various other regulatory policy issues.

Education:

B.A. (Economics) - University of Maryland, 1971.

M.A. (Economics) - University of Maryland, 1974.

Ph.D. candidate - University of Maryland, completed all course work and qualifying examinations.

Previous Employment:

1981-2001 - Exeter Associates, Inc. (founding Principal).

1980-1981 - Member of the Economic Evaluation Directorate, The Aerospace Corporation, Washington, D.C. office.

1977-1980 - Economist, Washington, D.C. consulting firm.

1972-1977 - Research/Teaching Assistant and Instructor, Department of Economics, University of Maryland (College Park).

1975-1977 - Lecturer in Business/Economics, Montgomery College.

Professional Work Experience:

Mr. Kahal has more than twenty years experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc. and for the next 20 years he served as a Principal and corporate officer in the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted both by Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at

Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College teaching courses on economic principles, business and economic development.

Publications and Consulting Reports:

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980, (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.

Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983, (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting, (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities," (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author, (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting," (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk," (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985, (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company -- Past and Present, prepared for the Texas Public Utility Commission, December 1985, (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy -- An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.) authored two chapters, November 1988, PPRP-CEIR-6.

Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum)

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994. Prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.)

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).
The Economic Feasibility of Air Emissions Controls at the Brandon Shores and Morgantown Coal-fired Power Plants, February 2005, (prepared for the Chesapeake Bay Foundation).

The Economic Feasibility of Power Plant Retirements on the Entergy System, September 2005 with Phil Hayet (prepared for the Louisiana Public Service Commission).

Expert Report on Capital Structure, Equity and Debt Costs, prepared for the Edmonton Regional Water Customers Group, August 30, 2006.

Maryland's Options to Reduce and Stabilize Electric Power Prices Following Restructuring, with Steven L. Estomin, prepared for the Power Plant Research Program, Maryland Department of Natural Resources, September 2006.

Expert Report of Matthew I. Kahal, on behalf of the U. S. Department of Justice, August 2008, Civil Action No. IP-99-1693C-MIS.

Conference and Workshop Presentations:

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995, (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on "Restructuring the Electric Industry," sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen '97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers' Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, October 2, 2002. (Presentation on Performance-Based Ratemaking and panelist on RTO issues). Baton Rouge, Louisiana.

Virginia State Corporation Commission/Virginia State Bar, Twenty Second National Regulatory Conference, May 10, 2004. (Presentation on Electric Transmission System Planning.) Williamsburg, Virginia.

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	Docket Number	Utility	Jurisdiction	Client	Subject
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic Impacts of Proposed Rate Increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load Forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test Year Sales and Revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test Year Sales, Revenues, Costs and Load Forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-Use Pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load Forecasting, Marginal Cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for Plant, Load Forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA Standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-Use Pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-Use Rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting, Load Management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA Standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of Return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of Return, CWIP
16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP

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	Docket Number	Utility	Jurisdiction	Client	Subject
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of Return, Capital Structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of Equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of Return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of Return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of Return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of Return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of Return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of Return
31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, incentive rates, rate base
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds

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	Docket Number	Utility	Jurisdiction	Client	Subject
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of Return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of Return, capital Structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of Return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of Return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of Return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of Return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of Return
46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of Return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of Return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of Return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of Return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of Return, incentive regulation
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power

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66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of Return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of Return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of Return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of Return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of Return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of Return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of Return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	NA	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of Return

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82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of Return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of Return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of Return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of Return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et. al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of Return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of Return

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98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of Return
99.	90-256 January 1991	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
100.	U-17949A February 1991	South Central Bell Telephone Company	Louisiana	Louisiana PSC	Rate of Return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of Return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Environmental controls
103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Company Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Company	New Jersey	Rate Counsel	Rate of Return
108.	91-5032 August 1991	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of Return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of Return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of Return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return

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114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of Return
116.	P-870235 et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts
117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of Return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of Return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of Return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of Return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of Return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of Return
128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation

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130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power Supply Clause
131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of Return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger Issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power Plant Certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of Return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of Return
137.	P-00930715 December 1993	Bell Telephone Company of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return, Financial Projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
139.	8583 February 1994	Conowingo Power Company	Maryland	Dept. of Natural Resources	Competitive Bidding for Power Supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Company	Minnesota	Attorney General	Rate of Return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of Return
142.	92-345, Phase II June 1994	Central Maine Power Company	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Company	Nevada	Federal Executive Agencies	Rate of Return
144.	94-0065 May 1994	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Rate of Return
145.	GR94010002J June 1994	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
146.	WR94030059 July 1994	New Jersey-American Water Company	New Jersey	Rate Counsel	Rate of Return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Company	Rate of Return
149.	R-00942986 July 1994	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, Emission Allowances
150.	94-121 August 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger Savings and Allocations
152.	IPC-E-94-5 November 1994	Idaho Power Company	Idaho	Federal Executive Agencies	Rate of Return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of Return (Rebuttal Only)
154.	90-256 December 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of Return Industrial Contracts Trust Fund Earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of Return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of Return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class Cost of Service Issues
160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of Return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of Capital Spending Program
163.	ER95-625-000 et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of Return
164.	P-00950915 et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration Contract Amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of Equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of Return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of Return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of Return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues
175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning

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	Docket Number	Utility	Jurisdiction	Client	Subject
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition
189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459 November 1997	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015	Allegheny Power System	Pennsylvania	Office of Consumer Advocate	Merger Issues

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	Docket Number	Utility	Jurisdiction	Client	Subject
	November 1997	DQE, Inc.			
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return
196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
203.	Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204.	Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205.	Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206.	Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs
207.	Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208.	Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209.	Docket No. EC-98-40-000, et al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation

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	Docket Number	Utility	Jurisdiction	Client	Subject
210.	Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211.	Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212.	WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213.	2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214.	DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215.	00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216.	Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations
217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power
219.	Case No. 21453, et al July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453, et al. February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs
223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs

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	Docket Number	Utility	Jurisdiction	Client	Subject
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Connectivity	Maryland	MD Energy Administration	Merger Issues
231.	U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232.	U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233.	3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234.	99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review
235.	U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Uprates Purchase Power
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237.	U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238.	R-00016849C001 et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return
239.	U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240.	U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241.	U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract

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	Docket Number	Utility	Jurisdiction	Client	Subject
242.	8936 October 2002	Delmarva Power & Light	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243.	U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245.	02S-315EG November 2002	Public Service Company of Colorado	Colorado	Fed. Executive Agencies	Rate of Return
246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Administration Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery
252.	C2-99-1181 October 2003	Ohio Edison Company	U.S. District Court	U.S. Department of Justice, et al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)
255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
259.	E-01345A-03-0437 January 2004	Arizona Public Service Company	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Company	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant Purchase and Cost Recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings
269.	EF03070532 March 2005	Public Service Electric & Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract
273.	05-0045-EI June 2005	Florida Power & Lt.	Florida	Federal Executive Agencies	Rate of Return
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration	POLR Service

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	Docket Number	Utility	Jurisdiction	Client	Subject
275.	U-28155 August 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Independent Coordinator of Transmission Plan
276.	U-27866-A September 2005	Southwestern Electric Power Company	Louisiana	LPSC Staff	Purchase Power Contract
277.	U-28765 October 2005	Cleco Power LLC	Louisiana	LPSC Staff	Purchase Power Contract
278.	U-27469 October 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Avoided Cost Methodology
279.	A-313200F007 October 2005	Sprint (United of PA)	Pennsylvania	Office of Consumer Advocate	Corporate Restructuring
280.	EM05020106 November 2005	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Merger Issues
281.	U-28765 December 2005	Cleco Power LLC	Louisiana	LPSC Staff	Plant Certification, Financing, Rate Plan
282.	U-29157 February 2006	Cleco Power LLC	Louisiana	LPSC Staff	Storm Damage Financing
283.	U-29204 March 2006	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Purchase power contracts
284.	A-310325F006 March 2006	Alltel	Pennsylvania	Office of Consumer Advocate	Merger, Corporate Restructuring
285.	9056 March 2006	Generic	Maryland	Maryland Energy Administration	Standard Offer Service Structure
286.	C2-99-1182 April 2006	American Electric Power Utilities	U. S. District Court Southern District, Ohio	U. S. Department of Justice	New Source Review Enforcement (expert report)
287.	EM05121058 April 2006	Atlantic City Electric	New Jersey	Ratepayer Advocate	Power plant Sale
288.	ER05121018 June 2006	Jersey Central Power & Light Company	New Jersey	Ratepayer Advocate	NUG Contracts Cost Recovery
289.	U-21496, Subdocket C June 2006	Cleco Power LLC	Louisiana	Commission Staff	Rate Stabilization Plan
290.	GR0510085 June 2006	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Rate of Return (gas services)

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	Docket Number	Utility	Jurisdiction	Client	Subject
291.	R-000061366 July 2006	Metropolitan Ed. Company Penn. Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
292.	9064 September 2006	Generic	Maryland	Energy Administration	Standard Offer Service
293.	U-29599 September 2006	Cleco Power LLC	Louisiana	Commission Staff	Purchase Power Contracts
294.	WR06030257 September 2006	New Jersey American Water Company	New Jersey	Rate Counsel	Rate of Return
295.	U-27866/U-29702 October 2006	Southwestern Electric Power Company	Louisiana	Commission Staff	Purchase Power/Power Plant Certification
296.	9063 October 2006	Generic	Maryland	Energy Administration Department of Natural Resources	Generation Supply Policies
297.	EM06090638 November 2006	Atlantic City Electric	New Jersey	Rate Counsel	Power Plant Sale
298.	C-2000065942 November 2006	Pike County Light & Power	Pennsylvania	Consumer Advocate	Generation Supply Service
299.	ER06060483 November 2006	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
300.	A-110150F0035 December 2006	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
301.	U-29203, Phase II January 2007	Entergy Gulf States Entergy Louisiana	Louisiana	Commission Staff	Storm Damage Cost Allocation
302.	06-11022 February 2007	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
303.	U-29526 March 2007	Cleco Power	Louisiana	Commission Staff	Affiliate Transactions
304.	P-00072245 March 2007	Pike County Light & Power	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
305.	P-00072247 March 2007	Duquesne Light Company	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
306.	EM07010026 May 2007	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Power Plant Sale

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	Docket Number	Utility	Jurisdiction	Client	Subject
307.	U-30050 June 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
308.	U-29956 June 2007	Entergy Louisiana	Louisiana	Commission Staff	Black Start Unit
309.	U-29702 June 2007	Southwestern Electric Power Company	Louisiana	Commission Staff	Power Plant Certification
310.	U-29955 July 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contracts
311.	2007-67 July 2007	FairPoint Communications	Maine	Office of Public Advocate	Merger Financial Issues
312.	P-00072259 July 2007	Metropolitan Edison Co.	Pennsylvania	Office of Consumer Advocate	Purchase Power Contract Restructuring
313.	EO07040278 September 2007	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Energy Program Financial Issues
314.	U-30192 September 2007	Entergy Louisiana	Louisiana	Commission Staff	Power Plant Certification Ratemaking, Financing
315.	9117 (Phase II) October 2007	Generic (Electric)	Maryland	Energy Administration	Standard Offer Service Reliability
316.	U-30050 November 2007	Entergy Gulf States	Louisiana	Commission Staff	Power Plant Acquisition
317.	IPC-E-07-8 December 2007	Idaho Power Co.	Idaho	U.S. Department of Energy	Cost of Capital
318.	U-30422 (Phase I) January 2008	Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
319.	U-29702 (Phase II) February, 2008	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Certification
320.	March 2008	Delmarva Power & Light	Delaware State Senate	Senate Committee	Wind Energy Economics
321.	U-30192 (Phase II) March 2008	Entergy Louisiana	Louisiana	Commission Staff	Cash CWIP Policy, Credit Ratings
322.	U-30422 (Phase II) April 2008	Entergy Gulf States - LA	Louisiana	Commission Staff	Power Plant Acquisition
323.	U-29955 (Phase II) April 2008	Entergy Gulf States - LA Entergy Louisiana	Louisiana	Commission Staff	Purchase Power Contract

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	Docket Number	Utility	Jurisdiction	Client	Subject
324.	GR-070110889 April 2008	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of Capital
325.	WR-08010020 July 2008	New Jersey American Water Company	New Jersey	Rate Counsel	Cost of Capital
326.	U-28804-A August 2008	Entergy Louisiana	Louisiana	Commission Staff	Cogeneration Contract
327.	IP-99-1693C-M/S August 2008	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/ Environmental Protection Agency	Clean Air Act Compliance (Expert Report)
328.	U-30670 September 2008	Entergy Louisiana	Louisiana	Commission Staff	Nuclear Plant Equipment Replacement
329.	9149 October 2008	Generic	Maryland	Department of Natural Resources	Capacity Adequacy/Reliability
330.	IPC-E-08-10 October 2008	Idaho Power Company	Idaho	U.S. Department of Energy	Cost of Capital
331.	U-30727 October 2008	Cleco Power LLC	Louisiana	Commission Staff	Purchased Power Contract
332.	U-30689-A December 2008	Cleco Power LLC	Louisiana	Commission Staff	Transmission Upgrade Project
333.	IP-99-1693C-M/S February 2009	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/EPA	Clean Air Act Compliance (Oral Testimony)
334.	U-30192, Phase II February 2009	Entergy Louisiana, LLC	Louisiana	Commission Staff	CWIP Rate Request Plant Allocation
335.	U-28805-B February 2009	Entergy Gulf States, LLC	Louisiana	Commission Staff	Cogeneration Contract
336.	P-2009-2093055, et al. May 2009	Metropolitan Edison Pennsylvania Electric	Pennsylvania	Office of Consumer Advocate	Default Service
337.	U-30958 July 2009	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract
338.	EO08050326 August 2009	Jersey Central Power Light Co.	New Jersey	Rate Counsel	Demand Response Cost Recovery
339.	GR09030195 August 2009	Elizabethtown Gas	New Jersey	New Jersey Rate Counsel	Cost of Capital

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	Docket Number	Utility	Jurisdiction	Client	Subject
340.	U-30422-A August 2009	Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase
341.	CV 1:99-01693 August 2009	Duke Energy Indiana	Federal District Court – Indiana	U. S. DOJ/EPA, *et al.*	Environmental Compliance Rate Impacts (Expert Report)
342.	4065 September 2009	Narragansett Electric	Rhode Island	Division Staff	Cost of Capital
343.	U-30689 September 2009	Cleco Power	Louisiana	Staff	Cost of Capital, Rate Design, Other Rate Case Issues
344.	U-31147 October 2009	Entergy Gulf States Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
345.	U-30913 November 2009	Cleco Power	Louisiana	Staff	Certification of Generating Unit
346.	M-2009-2123951 November 2009	West Penn Power	Pennsylvania	Office of Consumer Advocate	Smart Meter Cost of Capital (Surrebuttal Only)
347.	GR09050422 November 2009	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Cost of Capital
348.	D-09-49 November 2009	Narragansett Electric	Rhode Island	Division Staff	Securities Issuances
349.	U-29702, Phase II November 2009	Southwestern Electric Power Company	Louisiana	Commission Staff	Cash CWIP Recovery
350.	U-30981 December 2009	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Storm Damage Cost Allocation
351.	U-31196 (ITA Phase) February 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
352.	ER09080668 March 2010	Rockland Electric	New Jersey	Rate Counsel	Rate of Return
353.	GR10010035 May 2010	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of Return
354.	P-2010-2157862 May 2010	Pennsylvania Power Co.	Pennsylvania	Consumer Advocate	Default Service Program
355.	10-CV-2275 June 2010	Xcel Energy	U.S. District Court Minnesota	U.S. Dept. Justice EPA	Clean Air Act Enforcement

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	Docket Number	Utility	Jurisdiction	Client	Subject
356.	WR09120987 June 2010	United Water New Jersey	New Jersey	Rate Counsel	Rate of Return
357.	U-30192, Phase III June 2010	Entergy Louisiana	Louisiana	Staff	Power Plant Cancellation Costs
358.	31299 July 2010	Cleco Power	Louisiana	Staff	Securities Issuances
359.	App. No. 1601162 July 2010	EPCOR Water	Alberta, Canada	Regional Customer Group	Cost of Capital
360.	U-31196 July 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract

APPENDIX B

CONSIDERED DOCUMENTS

(1) Annual Report of the Detroit Edison Company for the year ending December 31, 2009, submitted to the Michigan Public Service Company, MPSC Form P-521. (April 19, 2010)

(2) Michigan Energy Appraisal, (Semiannual Projection of Energy Supply and Demand, Summer Outlook 2010), Michigan Department of Energy, Labor & Economic Growth, May 26, 2010. httpS://www.dleg.state.mi.us/mpsc/reports/energy/10summer/index.htm

(3) 2010 Summer Resource Assessment, Midwest Independent System Operator, submitted in MPSC Case No. U-16160, April 2010.

(4) Summer 2010 Resource Adequacy Plan, the Detroit Edison Company, March 31, 2010, MPSC Case No. U-16160.

(5) 2010 Summer Reliability Assessment, North American Electric Reliability Corporation, May 2010.

(6) SEC Form 10-K for DTE Energy Company for the year ending December 31, 2009.

(7) SEC Form 10-K for The Detroit Edison Company, for the year ending December 31, 2009.

(8) Letter to Mr. William Presson (Michigan Department of Environmental Quality) from Kelly L. Guertin (DTE Energy Company), March 12, 2010.

(9) Qualification and Direct Testimony of Sherrie L. Siefman (The Detroit Edison Company), MPSC Case No. U-15768, January 2009.

(10) Qualification and Direct Testimony of Sherrie L. Siefman (The Detroit Edison Company), MPSC Case No. U-16047, September 2009.

(11) Qualifications and Direct Testimony of Paul Fessler (The Detroit Edison Company), MPSC Case No. U-15768, January 2009.

(12) DTE Energy Company, "Japan Investors Meeting," April 14-16, 2010. (Slide presentation to securities analysts, available at www.detenergy.com)

(13) Letter to Sabrina Argenticri (U.S. Environmental Protection Agency) from Michael J. Solo, Jr. (DTE Energy), June 1, 2010.

(14) Letter to Mark Palermo (U.S. Environmental Protection Agency) from Michael J. Solo, Jr. (DTE Energy), June 3, 2010.

Exhibit 12

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF MICHIGAN

UNITED STATES OF AMERICA	)
	)
	)
Plaintiff,	)
	)
v.	)
	)
DTE ENERGY COMPANY, and DETROIT EDISON COMPANY	)
	)
	)
Defendants.	)
	)

DECLARATION OF
JOEL SCHWARTZ

1. I am a Professor in the Departments of Environmental Health and Epidemiology at the Harvard School of Public Health, in the Department of Medicine at Harvard Medical School, Director of the Harvard Center for Risk Analysis, member of the faculty of the Environmental Biostatistics program, of the cardiovascular epidemiology program, and on the Steering Committee of the Harvard University Center for the Environment. I am also a former member of the board of Councilors of the International Society for Environmental Epidemiology, and on the Editorial Board of the American Journal of Respiratory and Critical Care Medicine. I have served on two National Academy of Sciences panels, and was a recipient of a John D. and Catherine T. MacArthur Fellowship. I am the most cited author in the field of air pollution research. I have over 416 peer reviewed papers published or in press, which have been cited over 21,000 times in other peer reviewed publications. Over 200 of these scientific papers have examined particulate air pollution. I have made particulate air pollution and ground-level ozone (smog) a major focus of my research which ranges from time series studies to cohort

studies to genetic studies, and from studies focused on critical events (e.g. deaths, heart attacks) to studies addressing mechanisms and exposure. I have testified before Congress twice about particulate air pollution and testified as an expert in the health effects of air pollution in federal court.

I. SUMMARY OF CONCLUSIONS

2. Particulate air pollution from combustion is created in two ways. First, combustion processes produce particles directly, such as the soot coming off of a fire. In addition, many of the gases that are emitted by combustion, such as SO_2 and NO_x react in the atmosphere and produce particles. These are sometimes called secondary particles, as they left the source as a gas. In addition NO_x reacts with hydrocarbons in the atmosphere to produce ozone. Hence emissions of SO_2 and NO_X from coal burning power plants are major sources of particles and ozone in the air people breathe.

3. There is clear, convincing evidence that this particulate air pollution is not merely a nuisance darkening our skies. It kills people. And the number of people it kills each year in the United States is not small—it is larger than the number of deaths each year from AIDS, breast cancer, and prostate cancer put together. Hence even a fraction of a percent change in this number would be more people than die in a major airplane crash.

4. In addition to killing people, particles trigger heart attacks, destabilize people with heart failure, driving them into the hospital, and exacerbate respiratory infections, leading to increased hospital admissions for those conditions.

5. These patterns are not due to failure to exclude other possible explanations. Similar associations are seen when we control for other pollutants and weather, when we control

for pre-existing disease, smoking, etc. Moreover, animal and toxicologic studies show changes in intermediary endpoints (e.g. electrocardiogram patterns, measures of inflammation, blood pressure) that are consistent with the changes seen in the epidemiologic studies.

6. Further, studies have demonstrated down to the lowest measured exposure that these effects do not have a threshold, and that the deaths produced by particles are not just being advanced by a few weeks, but can reduce the life expectancy of entire populations by several years.

7. All of this indicates that any increase in particle concentrations has substantial effects on human health, including resulting in early deaths. Details justifying these conclusions are below. I start with mortality, and move on to other serious health effects such as heart attacks, hospital admissions, etc.

8. In this case, I was asked to assume that additional pollution controls at Monroe Unit 2 would reduce emissions by 26,525 tons of SO2 and 7942 tons of NOX per year. Based on my research, I estimate that reducing emissions by that amount would result in 90 fewer premature deaths per year and benefit to society worth approximately $542 million per annum.

9. A collection of sources supporting this discussion are listed in Attachment B. I am being compensated at a rate of $197 per hour for my work on this matter.

II. BACKGROUND ON ENVIRONMENTAL EXPOSURE-HEALTH STUDIES

10. The effects of exposures to environmental agents are generally studied using three types of studies. In toxicological studies, animals are exposed to high doses of the toxic agent, to see what responses are elicited. In controlled human exposure chambers, volunteers, usually

healthy individuals, are exposed to high doses of the toxic agents. Finally, epidemiology studies examine the species of interest at the exposures of interest.

11. The case of airborne particles is one where epidemiology particularly takes precedence. First, the effect of air pollutants can be quite different at high doses. Moreover particles seem to increase oxidative compounds in the body, putting a burden on the antioxidant defenses of the body. These differ by species. Rodents, for example, manufacture vitamin C, whereas humans require dietary intake. Second, the serious impacts of particles (and other air pollutants) seem concentrated in certain susceptible populations, such as diabetics, persons with heart disease, etc., making it very difficult to put such people in controlled exposure chambers. Finally, particles are a complex mixture, with, for example, toxic metals deposited on top of ammonium sulfate cores, pieces of soot particles stuck together, etc. Laboratory generated particles rarely have any relevance for real life particles, and laboratory animals are rarely representative of the diseases conveying susceptibility.

12. In an epidemiology study, one examines whether variations among people in their exposure are predictive of variations among people in their health. Because one can examine the full population, it is easy to incorporate persons with genetic profiles or medical conditions that make them vulnerable. Also, because air pollution is usually measured continuously, one does not have to decide in advance what the appropriate averaging time is for exposure. That is, one does not need to decide in advance to expose people to 1 hour, 2 hours, or 6 hours of exposure. One can determine it in the study. And if it is 24 or 48 hours of exposure that is the most relevant, exposure chambers are not feasible at all.

13. Toxicology studies and human exposure studies are valuable because, despite the limitations above, they provide insight into mechanisms by which exposure, in our case to

particles, produces biological effects. Overall, there have been thousands of studies of the health effects of particles in the last two decades, and the overwhelming scientific consensus is that there is no doubt that they are associated with early deaths, as well as a range of other adverse events. These studies began years ago, and over time the metric by which airborne particles are measured has changed. In the late 1980's EPA measured particles as PM_{10}, particles less than 10 micrometers in diameter. This is small enough to get down peoples' throats and into the lungs. Since the late 1990's EPA has measured (and regulated) both PM_{10} and $PM_{2.5}$, which is particles less than 2.5 micrometers in diameter. The $PM_{2.5}$ subset of PM_{10} is thought be more toxic, because combustion particles are all found in that size range, and it is more likely to deposit deeper in the lung. In urban areas in the U.S., 70-90% of PM_{10} is usually $PM_{2.5}$, so studies of PM_{10} are quite relevant for $PM_{2.5}$ health effects.

14. Below, I first summarize the overwhelming scientific consensus, and then summarize my conclusions. I follow that with a more detailed explanation of the basis for my conclusions.

III. THE SCIENTIFIC CONSENSUS

15. Over the past two decades an overwhelming scientific consensus has developed about the health effects of particulate air pollution. It is widely accepted that such particles reduce life expectancy, trigger heart attacks, and have a wide range of other adverse effects on health. Several of the most reputed health organizations have noted the consensus on the health effects of particulate matter. For example, the World Health Organization, in setting a global maximum PM_{10} standard of 20 $\mu g/m^3$ in 2005, roughly equivalent to the U.S. EPA standard of 15 $\mu g/m^3$ for $PM_{2.5}$, stated:

> By reducing particulate matter pollution from 70 to 20 micrograms per cubic metre as set out in the new Guidelines, we estimate that we can cut deaths by around 15%," said Dr. Maria Neira, WHO Director of Public Health and the Environment. "By reducing air pollution levels, we can help countries to reduce the global burden of disease from respiratory infections, heart disease, and lung cancer which they otherwise would be facing.

Their press release went on to say:

> These new guidelines have been established after a worldwide consultation with more than 80 leading scientists and are based on review of thousands of recent studies from all regions of the world. As such, they present the most widely agreed and up-to-date assessment of health effects of air pollution, recommending targets for air quality at which the health risks are significantly reduced. We look forward to working with all countries to ensure these Guidelines become part of national law

and, "For example, in the European Union, the smallest particulate matter alone ($PM_{2.5}$) causes an estimated loss of statistical life expectancy of 8.6 months for the average European."

16. Earlier, in the 2002 World Health Report, WHO concluded "Particulate air pollution (i.e. particles small enough to be inhaled into the lung) is consistently and independently related to the most serious [acute and chronic health] effects, including lung cancer and other cardiopulmonary mortality."

17. A more recent review was conducted in the United States. As part of the Clean Air Act, the U.S. EPA is required to have its summary review of the science about each criteria air pollutant reviewed by an external, statutory Clean Air Science Advisory Board (CASAC). In reviewing the EPA Staff Paper the CASAC stated, "In summary, the epidemiologic evidence, supported by emerging mechanistic understanding, indicates adverse effects of $PM_{2.5}$ at current annual average levels below 15 $\mu g/m^3$." In its letter of 6/29/06, CASAC reiterated:

> The CASAC recommended changes in the annual fine-particle standard because *there is clear and convincing scientific evidence that significant adverse human-health effects occur in response to short-term and chronic particulate matter exposures at and below 15 µg/m3, the level of the current annual $PM_{2.5}$ standard.*

It goes on to say:

> Significantly, we wish to point out that the CASAC's recommendations were consistent with the mainstream scientific advice that EPA received from virtually every major medical association and public health organization that provided their input to the Agency, including the American Medical Association, the American Thoracic Society, the American Lung Association, the American Academy of Pediatrics, the American College of Cardiology, the American Heart Association, the American Cancer Society, the American Public Health Association, and the National Association of Local Boards of Health. Indeed, to our knowledge there is no science, medical or public health group that disagrees with this very important aspect of the CASAC's recommendations. EPA's recent "expert elicitation" study (Expanded Expert Judgment Assessment of the Concentration-Response Relationship Between $PM_{2.5}$ Exposure and Mortality, September 21, 2006) only lends additional support to our conclusions concerning the adverse human health effects of $PM_{2.5}$.

18. As noted above, these conclusions are supported by all the major associations of health professionals, which include as members almost all researchers on heart disease, lung disease, and cancer. In their letter to the EPA administrator on the $PM_{2.5}$ standard the health professional organizations stated:

> There is a robust and growing body of evidence linking PM to adverse health effects. PM has now been linked to a broad range of adverse health effects, both respiratory and cardiovascular, in epidemiological and toxicological research. Epidemiological research has shown an association between PM exposure and increased risk for mortality. Time-series studies reported in the early 1990s showed that day-to-day variation in PM concentration was associated with mortality counts. These studies in selected cities have now been followed by national-level time-series analyses in the United States and Europe that pool data from broad regions to produce national estimates of the effect of PM on daily mortality.
>
> For example, in 90 U.S. cities, the National Morbidity and Mortality Air Pollution Study (NMMAPS) estimated a 0.2% increase of all-cause mortality per 10 $\mu g/m^3$ increase in PM_{10}. Risk was highest in the northeast and for cardiovascular and respiratory causes of death. Findings of follow-up studies, including most notably the Harvard Six Cities Study and the American Cancer Society's Cancer Prevention (CPS) II Study, show that the resulting loss of life may be substantial. The time-series studies show a linear relationship between PM concentration and risk at concentrations measured routinely in many U.S. cities.
>
> There is a now a substantial, parallel literature on PM and morbidity. Studies have addressed PM and risk for hospitalization and other clinical outcomes and pre-clinical

biomarkers. Since the 1997 PM NAAQS, there has been an explosion of research on cardiovascular consequences of exposure to PM indicating short-term and long-term effects of PM on cardiovascular health.

A recent study, that includes data from over 11 million Medicare beneficiaries, shows that even small increases in exposure to PM results in increased admissions for cardiac and respiratory conditions, including heart and vascular diseases, heart failure, chronic obstructive pulmonary disease and respiratory infections. The effect was even greater in participants over 75 years old, in terms of heart problems and COPD than participants 65 – 74 years old.

In short, a significant body of research has described potential mechanisms for and the range of health effects caused by PM air pollution. The undersign physician organizations find the body of scientific evidence to be rigorous, comprehensive and compelling enough to justify a significant tightening of the existing NAAQS PM standards.

Sincerely,

American Thoracic Society

American Academy of Pediatrics

American College of Cardiology

American Association of Cardiovascular and Pulmonary Rehabilitation

National Association for the Medical Direction of Respiratory Care

19. In separate comments, the *American Medical Association* wrote:

The new evidence on harmful effects of PM is substantial. PM has been linked to a broad range of adverse health effects, both respiratory and cardiovascular, in epidemiologic and toxicologic research. Studies of daily variation in concentrations and national level time-series analyses have linked PM with increased morbidity and mortality. Many U.S. and Canadian studies are available that provide evidence of associations between $PM_{2.5}$ and serious health effects in areas with air quality at and above the level of the 1997 annual standard (15 μg/m3). Newer short term mortality studies provide evidence of statistically significant associations with $PM_{2.5}$ in areas with long-term average concentrations of 13 to 14 $\mu g/m^3$, concentrations that are below the 1997 standard. Short-term studies of emergency room visits and cardiovascular mortality suggest measurable health effects at $PM_{2.5}$ concentrations of ~12 $\mu g/m^3$. A recent study (Dominici F, Peng D, Bell ML et al. *JAMA*; 2006; 295:1127-1134) showed that $PM_{2.5}$ concentrations are associated with short-term increases in hospital admissions for cardiovascular and respiratory diseases among Medicare enrollees, arguing for setting a $PM_{2.5}$ standard that is adequate to protect the health of these individuals. The AMA supports the recommendations of EPA staff and the Clean Air Scientific Advisory Committee to EPA for more stringent air quality standards. In fact, several physician organizations, including the American Thoracic Society, American College of Cardiology, American College of Preventive Medicine, and the American Academy of Pediatrics, support a more stringent $PM_{2.5}$ standard of 12 $\mu g/m^3$ for

> the average annual standard; 25 μg/m^3 for the 24-hour standard; and use of the 99th percentile form for compliance determination. The AMA believes the Administrator should adopt these more stringent standards in order to provide adequate protection for the public from the adverse health effects of both long- and short-term exposures to fine particulate matter in the ambient air.

20. Hence every major scientific body involved in either research or the evaluation of research relating to particulate air pollution has concluded that it is a major health hazard, whose consequences include early deaths.

21. The American Heart Association recently published a new review in 2010 of the impact of particles on cardiovascular health in Circulation, the world's leading peer reviewed journal on heart disease. The abstract of that peer reviewed paper summarizes the conclusions as follows:

> In 2004, the first American Heart Association scientific statement on "Air Pollution and Cardiovascular Disease" concluded that exposure to particulate matter (PM) air pollution contributes to cardiovascular morbidity and mortality. In the interim, numerous studies have expanded our understanding of this association and further elucidated the physiological and molecular mechanisms involved. The main objective of this updated American Heart Association scientific statement is to provide a comprehensive review of the new evidence linking PM exposure with cardiovascular disease, with a specific focus on highlighting the clinical implications for researchers and healthcare providers. The writing group also sought to provide expert consensus opinions on many aspects of the current state of science and updated suggestions for areas of future research. On the basis of the findings of this review, several new conclusions were reached, including the following: Exposure to PM □2.5 μm in diameter (PM2.5) over a few hours to weeks can trigger cardiovascular disease–related mortality and nonfatal events; longer-term exposure (eg, a few years) increases the risk for cardiovascular mortality to an even greater extent than exposures over a few days and reduces life expectancy within more highly exposed segments of the population by several months to a few years; reductions in PM levels are associated with decreases in cardiovascular mortality within a time frame as short as a few years; and many credible pathological mechanisms have been elucidated that lend biological plausibility to these findings. It is the opinion of the writing group that the overall evidence is consistent with a causal relationship between PM2.5 exposure and cardiovascular morbidity and mortality. This body of evidence has grown and been strengthened substantially since the first American Heart Association scientific statement was published. Finally, PM2.5 exposure is deemed a modifiable factor that contributes to cardiovascular morbidity and mortality.

22. The US EPA has recently prepared a new Integrated Science Assessment summarizing the state of the science about particulate air pollution, which has been reviewed by the Clean Air Scientific Advisory Committee. That assessment states:

> Epidemiologic studies that examined the effect of PM2.5 on cardiovascular emergency department (ED) visits and hospital admissions (HA) reported consistent positive associations (predominantly for ischemic heart disease [IHD] and congestive heart failure [CHF]), with the majority reporting increases ranging from 0.5 to 3.4% per 10 µg/m3 increase in PM2.5. These effects were observed in study locations with mean1 24-h avg PM2.5 concentrations ranging from 7-18 µg/m3 (Section 6.2.10), with effects becoming more precise and consistently positive in locations with mean PM2.5 concentrations of 13 µg/m3 and above (Figure 2-1). Toxicological studies have provided biologically plausible mechanisms (e.g., increased right ventricular pressure and diminished cardiac contractility) for the associations observed between PM2.5 and CHF in epidemiologic studies.
> and: There is also a growing body of evidence from controlled human exposure and toxicological studies demonstrating PM2.5-induced changes on markers of systemic oxidative stress and heart rate variability (HRV) (Section 6.2.1 and Section 6.2.9). Additional, but inconsistent effects of PM2.5 on BP, blood coagulation markers, and markers of systemic inflammation have also been reported across disciplines. Together, the collective evidence from epidemiologic, controlled human exposure, and toxicological studies is sufficient to conclude that a causal relationship exists between short- term exposures to PM and cardiovascular effects.

and:

> Collectively, the studies evaluated demonstrate a wide range of respiratory responses, and although results are not fully consistent and coherent across studies the evidence is sufficient to conclude that a causal relationship is likely to exist between short-term exposures to PM2.5 and respiratory effects.

and:

> An evaluation of the epidemiologic literature indicates consistent positive associations between short-term exposure to PM2.5 and all-cause, cardiovascular-, and respiratory-related mortality (Section 6.5.2.2.). ....Collectively, the epidemiologic literature provides evidence that a causal relationship is likely to exist between short-term exposures to PM2.5 and mortality.

and:

> Evidence from toxicological studies provides biological plausibility and coherence with studies of short-term exposure and CVD morbidity and mortality, as well as with studies that examined long- term exposure to PM2.5 and CVD mortality. Taken together, the evidence from epidemiologic and toxicological studies is sufficient to conclude that **a**

> **causal relationship exists between long-term exposures to PM2.5 and cardiovascular effects.** (emphasis in original)

(Integrated Science Assessment for Particulate Matter. Second External Review Draft. ISA: EPA/600/R-08/139B).

Commenting on the ISA, the CASAC, EPA's Statutorily mandated external science advisory committee stated, "CASAC also supports EPA's changes to the causal determinations for long-term exposure to PM2.5 and cardiovascular effects (from 'likely causal' to 'causal') and, "CASAC recommends 'upgrading' the causal classification for PM2.5 and total mortality to 'causal' for both the short-term and long-term time frames" (EPA-CASAC-10-001 Letter to the Administrator). That is, CASAC has concluded that the association between PM2.5 and deaths is causal.

IV. PARTICLES AND MORTALITY

23. Several different types of studies have been used to examine the relationship between particles and mortality: long term exposure studies have focused on the association between longer term exposure to particles and life expectancy, whereas other studies have looked at the acute responses within a few days of exposure. Finally, there are some intermediary studies that attempt to bridge the gap. Within studies of longer term exposure there are further distinctions based on whether the exposure contrast is just between cities, or whether it includes, or is limited to, contrasts within a metropolitan area. Also, some studies incorporate changes over time in exposure. I discuss these various types of studies below.

IV.a. Long Term Exposure Studies

Mortality

24. I find, as did the major scientific organizations, that there is clear, convincing evidence that exposure to particles shortens life expectancy by substantial amounts. I base this judgment on the extensive literature, as outlined below.

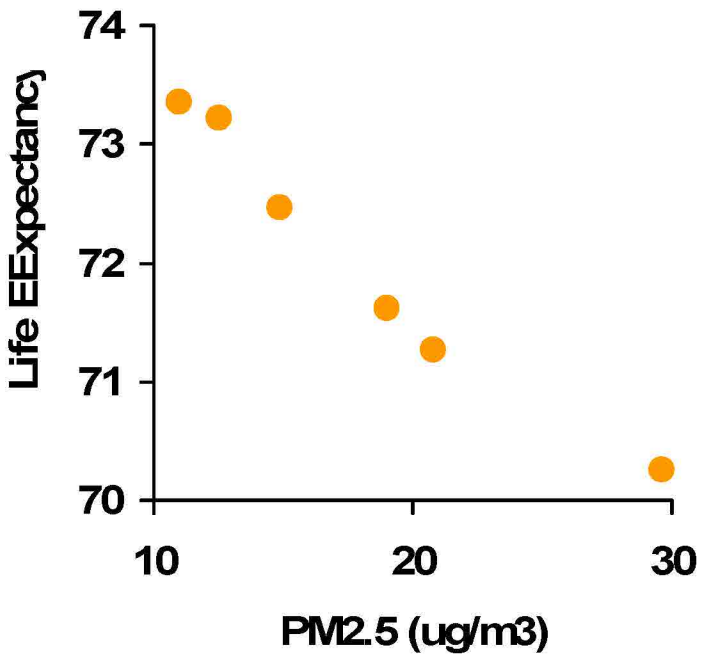
25. In 1970, Lave and Seskin published a paper regressing age standardized mortality rates in US cities against average particle concentrations in those cities. The advantage of that study was that the mortality experience of the entire population of each city was compared to the average particle concentration from the population- oriented monitors in the city. The difficulty was that no individual level covariates (i.e. other individual factors such as hypertension, diabetes, smoking, etc that may differ on average between the people in different cities, and might explain the differences between those cities in mortality rates) were controlled, raising questions about confounding (i.e. that another variable explains the observed association).

26. More recent studies have alleviated that problem by recruiting cohorts of individuals in various areas, and measuring those individual covariates. An issue with most of those cohort studies is that they are convenience samples, and unlike Lave and Seskin, do not capture the typical mortality experience or the typical exposure of the population of the city they live in. If the convenience sample differed in health and exposure from the population average similarly in all locations, this would ameliorate the problem. However, we cannot be sure this is true. Specifically, the American Cancer Society (ACS) cohort was recruited from friends of the volunteers of the society. The ACS volunteers in city A may represent a healthier, and less exposed subset of city A then they do in city B.

27. This is problematic for two reasons. First there is potential confounding. If, for example, the cities with higher exposures had **systematically** less healthy subjects recruited, this would tend to enhance the size of the air pollution effect. If they **systematically** had more healthy subjects, it would attenuate the size of the air pollution effect. I know of no reason to assume that either is true. Most people are unaware of the relative pollution level in their town, and hence this is unlikely to effect volunteering for the American Cancer Society—I would expect such differences to occur by chance, and, on average, not be related to pollution levels. However, there undoubtedly are some random fluctuations in the relative health and relative exposure of the subjects from city to city. This is likely to lead to an underestimate of the effect of exposure on mortality risk, which is the general result of such non-differential measurement error. Moreover, studies where the relation between sample health and population health varies more substantially from city to city have a greater risk of this additional uncertainty and potential bias.

28. These concerns apply to all of the cohort studies, with the obvious exception of the Six City Study. The Six City Study chose a neighborhood within each city, recruited a **random** sample of that neighborhood, and put a population oriented particle monitor in the middle of each neighborhood. Most subjects lived within a few kilometers of that central monitor, and the exposure error was much lower than in studies using the average of all monitors in a greater metropolitan area. Further, bias due to differential sampling in different locations was eliminated by the random sampling. This means that the extra source of uncertainty, and extra downward bias, present in the other studies is not present in the Six City Analysis, suggesting this study should be given greater consideration. The reduction in life expectancy with higher exposure to particles that the Six City Study found was substantial, as indicated in

the figure below, which shows the life expectancy in each city, after adjusting for age, sex, cigarette smoking, occupation, education, obesity, and chronic disease, plotted against the mean $PM_{2.5}$ in that city. To put this in perspective, between 1995 and 2005 life expectancy in the U.S. increased by 2 years. Hence, PM can obliterate the effects of one and a half decades of medical progress on life expectancy.



29. Further evidence that the original ACS study (among others) underestimated the effects of particles on deaths comes from a recent reanalysis of the ACS study that only used monitors in the same county of residence of each subject to assign exposure (the original could assign subjects exposure from a monitor in a different county on the opposite side of the metropolitan area). That study found a higher coefficient for the effects of sulfate particles on mortality than the original study. Even more intriguingly, a recent study examined only the

22,905 participants of the ACS study living in Southern California using a geographic information system based exposure model, which captures the local exposure gradient within Southern California, and reported even larger effect size estimates for $PM_{2.5}$. Similarly, the Women's Health Initiative study found a larger effect on mortality when they used within-city exposure estimates. Hence the use of more localized measures of exposure, with resultant lower exposure error, generally has resulted in larger effect estimates.

30. Studies that examine change in exposure play an important role in understanding the effects of particles for several reasons. First, if particle-induced changes in health are permanent, and we have to wait for a new generation before seeing public health improvements follow the exposure reductions, there are important public health implications. It certainly dramatically affects any cost-benefit analyses. Secondly, showing that a change in exposure produces a change in response more directly addresses the causality of the association. If A causes B, then changing A will change B. Finally, cross-area comparisons between lung function, mortality rates, or any other response and cross-area variations in exposure across communities have the potential to be confounded by any unmeasured predictors of outcome that vary geographically (by confounder I mean another variable (e.g. hypertension) that is causally related to the outcome, and correlated with exposure, which actually explains the observed association between, in our case, particles and outcome). That is, if we controlled for that other variable the association with particles would go away.

31. Naturally, epidemiology studies try to identify such variables and control for them. Equally importantly, the Six City Study went further, and showed the association of air pollution with life expectancy before and after controlling for each potential confounder, such as smoking, hypertension, diabetes, occupational exposures, obesity, etc. There was no evidence of

confounding by any of the covariates examined except age. This provides some reassurance that confounding is unlikely. However, one cannot measure everything about a person's health, so it is always possible that such confounding exists. That is why it is important to look at multiple studies, and multiple study designs that have different potentials for such confounding. For example, unless we think that air pollution increases hypertension, in our example above, then there should not be any systematic correlation between air pollution levels in a city and the rate of hypertension. However, by chance, such a correlation may have occurred in one particular study limited to one set of locations. A different study in a different set of locations is less likely to have that confounding. And even if hypertension were systematically associated with higher air pollution in the U.S., perhaps because of the clustering of some behavior patterns in regions of the country that happen to be more polluted, why would that confounding remain if we only looked at differences in exposure and differences in mortality risk **within** a city, as in the new ACS analysis or the Women's Health Initiative analysis? And if there was something about the U.S. social structure that made that true in U.S. cities, why would that still be true in the Netherlands, with a very different social structure, where within city variations in particles were also associated with variations in the risk of death? Of course, all the cohort studies mentioned did control for hypertension, but there may be other unmeasured factors that are potential confounders in any one of them. The same arguments above apply—it is hard to see how those same unmeasured confounders could apply in all the cases above.

32. One other way to assure that the observed association is real is to conduct studies not merely in different locations, and across different scales of geography, but in different ways, including where exposure varies by time, and not geographic location. Examinations of year to year changes in exposure within location do not suffer the potential confounding that, as above,

some unmeasured confounder may differ from one city to another. Other variables, which do vary from year-to-year, might confound, but are unlikely to be correlated with the potential confounders of the cross-sectional associations. Hence, if associations are seen using this very different study design as well, it provides greater confidence that the associations are causal.

33. Consequently a key finding for cohort studies of mortality has come from studies examining changes in exposure and changes in mortality rates. Most of the cohort studies, including the original Six City Study, have contrasted a measure of long-term exposure with long term survival. They tell us that people live less long in more polluted cities. They do not, directly, tell us what mortality reduction accompanies a reduction in exposure. In a follow-up of the Harvard Six City Study, Laden and coworkers provide precisely that estimate. They examined a further 10 years of follow-up and mortality in the six cities. In some cities there was a substantial drop in pollution between the first and second follow-up periods, in some cities there was a moderate drop, and in some cities there was little or no change. The mortality rate ratios followed the same pattern: where there was a substantial drop in pollution there was a substantial improvement in life expectancy; where there was little change in pollution concentrations there was little change in life expectancy. The slope for change in exposure was similar to, but slightly higher, than the cross-sectional slope.

34. Again, if the mortality rates change within a town as the air pollution changes, and those changes fit on the same dose-response curve as the original cross-sectional association, this provides substantial assurance that the association is not confounded, because the factors that are likely to confound an association of temporal change are usually different from those that might confound a cross-sectional study, and there is no reason for the confounding of two different estimates by different confounders to produce similar estimated effects for particles.

35. Another follow-up analysis of the Six City Study looked at year-to-year changes in particle concentrations to examine two questions—does the dose-response continue below 15 $\mu g/m^3$; and what is the lag between change in exposure and change in mortality rate. Schwartz and coworkers, using a penalized spline with up to 18 degrees of freedom (essentially, a polynomial with 18 terms to capture any deviation from linearity), showed that the association was essentially linear down to 8 $\mu g/m^3$, where the data becomes sparse, and that the effects of reduced particle exposure on mortality appear to be mostly seen within two years. This conclusion is also supported by natural experiments. Pope and coworkers reported that mortality fell in the Utah valley in the year a strike closed a steel mill, and returned to its previous level the next year when mill operations resumed.

36. Because the uncertainties around the dose-response curve from fitting a particular model do not reflect the uncertainty in model choice we also used model averaging, where 32 models are fit explicitly, and averaged, weighted by their probability of being correct given the data. These models explicitly included the possibility of thresholds at multiple different particle concentrations. The association was indistinguishable from linear with no evidence of a threshold down to the lowest measured level of 8 $\mu g/m^3$. The finding of a rapid change in mortality risk associated with change in particle exposure in the Six City Study fits nicely with the similar report for lung function from the Swiss Cohort Study on Air Pollution and Lung Diseases in Adults (SAPALDIA) study.

37. Another recent study examined changes in life expectancy across 51 metropolitan areas in the United States, between 1980 and 2000. They found that 15% of the *increase* in life expectancy during that period came from *decreases* in air pollution, and that in the more polluted cities that cleaned up, life expectancy was increased by 10 months.

38. Recently, the study of Zanobetti and Schwartz examined over 190,000 subjects discharged alive from hospitals following myocardial infarctions (heart attacks). They looked at year to year changes in exposure **within** cities related to the probability of surviving that year, given the participant was alive on January 1. They adjusted for long term time trend, and did separate analyses within each of 21 cities. They then combined the results across cities. This approach does not allow any differences in exposure across a city to contribute to the association (which is only examined *within* the city), and again focuses on temporal changes in particles and mortality. Hence, as in the Six City analysis above, the set of potential confounders is quite different from those in a traditional cohort study. They reported a significant association with PM_{10} in this susceptible subgroup; they also found larger coefficients (the slope between exposure and mortality risk) than were seen in the Six City Study. A follow-up study looking at people with chronic bronchitis and emphysema in the same manner found a similar result. Another study in a similar vein was the work of Janke and coworkers. They looked at 354 local governmental units in England. They look at annual mortality rates for multiple years in each location, controlling for *location and local time trend*. In effect they are looking at whether random deviations from year to year in air pollution around the local means and local time trend are correlated with random deviations in mortality rates around the local mean and local time trend. Such a design leaves little room for confounding. They found a strong association with particulate air pollution.

39. Another new cohort study examined over 66,000 nurses living in the Northeast and upper Midwest. Using a spatial model that estimated monthly $PM_{2.5}$ concentrations at the addresses of each nurse, they found that a 10 $\mu g/m^3$ increase in $PM_{2.5}$ at the nurse's address was associated with a 26% increase in risk of dying in that year. Similar to my analysis of the Six

City Study, they found this increase was predominantly seen within a year of the change of exposure. This effect estimate is considerably higher than the Six City estimate, suggesting again the improved exposure results in higher estimates of the effects of particles on mortality.

40. More recently an innovative study modernized the Lave and Seskin approach. They looked at over 2300 counties in the Eastern US, and used remote satellite sensing data to estimate $PM_{2.5}$ concentrations. The satellite data allows the incorporation of the many counties without monitoring. This allowed them to include thousands of counties, rather than hundreds. They reported that standardized mortality rates for ischemic heart disease were associated with $PM_{2.5}$, in a region of the country where sulfates are a major source of $PM_{2.5}$

41. Another recent analysis, which extended the previous analyses of the ACS study to include more years and more data, importantly reported associations between sulfate particles, the type produced by coal burning power plants, and deaths from ischemic heart disease. Interestingly, they found that control for socio-economic status increased the risk associated with sulfates, rather than decreasing it.

42. This fits in quite well with developing studies looking at shorter term exposure to air pollution (discussed in the section on acute effects below), that have extended their ambit from looking at immediate effects of the last few day's exposure to include months of exposure. I examined the association of daily deaths and hospital admissions with particles when averaged over different periods, from days to months, after filtering out seasonal and long term trends. I found that the size of the PM effect increased as one went from days to periods of up to two months. At that point, the effect size estimates seemed intermediate between those reported in classical time series, which looked at yesterday's exposures, and those reported in the cohort studies.

43. As part of this approach, I developed a framework for thinking about this question. In this framework, the population is divided into a general pool, with low risk of dying, and a frail pool with high risk of dying in the near future. Because the causes of frailty can be at least partially reversible (e.g. subjects with pneumonia recover, subjects who survive a myocardial infarction have much lower risk of dying in the second month after the infarct than in the first, etc.) it is possible to transition back to the general pool from the frail pool. Meanwhile, other events can cause transitions from the general pool to the frail pool. If the effect of particles on the recruitment rate into, or retention in, the frail pool, is greater than the effects of particle exposure on the death rate out of the frail pool, increased exposure will result in an immediate increase in deaths (from the direct effect of particles on the death rate out of the frail pool), and also a delayed effect, as the increased population of the frail pool results in excess deaths over the next few months. The results of my studies indicate that this is the case.

44. A frequency domain regression approach by Zeger and coworkers showed similar results[22]. In several studies, Zanobetti and coworkers examined the time course of the mortality–death relationship directly, using distributed lag models. These models showed a pattern concordant with my hypothesis. There was an immediate increase in deaths following an increase in particle exposure, followed by a long tail of slightly increased deaths, stretching out for 40 days after the initial response. Time series studies by their nature have to control for season, and this makes it difficult to examine lags longer than a month or two, but the substantial increase in effect size reported by Zanobetti in these studies again suggests that the short term and long term responses to changes in airborne particles fall on a continuum.

45. Further support for this theory comes from recent studies looking at pregnancy outcomes and infant mortality. Both responses, by definition, involve exposures of less than a

year. For example, Bobak and Leon examined the cross–sectional association between air pollution and infant mortality rates across towns in the Czech Republic. A significant association was seen with particle concentrations. Woodruff and coworkers compared infant death rates in US cities with their levels of PM in the air. They excluded infant deaths in the first month after birth as likely to reflect complications of pregnancy and delivery, and found that PM_{10} was associated with higher death rates in the next 11 months of life. This excess risk seemed to be principally from respiratory illness, although sudden infant death syndrome deaths were also elevated. Further studies confirmed this association.

46. The association between airborne particles and mortality implies a very large public health impact. For example, the Laden paper suggests that an average 5 $\mu g/m^3$ decrease in $PM_{2.5}$ concentrations in the US would be associated with a 5-10% decrease in all cause mortality, which is 100,000-200,000 fewer deaths per year. **For comparison, the lower bound estimate is more deaths than from AIDS, breast cancer, and prostate cancer combined**.

Other Effects of Long Term Exposure

47. Long term exposure to particulate air pollution is not merely associated with increased risk of dying. It is associated with a wide range of other outcomes, which are in themselves consequential for health, and which also provide a coherent pattern with the mortality associations.

Lung Function

48. Lung function is one of these other outcomes that, in my judgment, is clearly affected by particles. Particles levels are associated with less growth of lung function among children and teenagers, and with faster decline of lung function in adults. This is important

because lung function is one of the best predictors of cardio-respiratory health and life expectancy, although the reasons are not completely understood. This makes associations between particulate air pollution and lung function relevant for other health outcomes. In the 1950's a study examined the lung function of British Postal workers, and found that workers in large urban areas with greater pollution consistently had lower lung function. The advantage of this study was that the postal workers generally stayed in the same counties all of their careers, and were of the same social status. Since then many other studies have reported associations between lung function and particles in the communities where people resided.

49. A recent example is the paper of Lubinski and coworkers, who reported decreases in the ratio of forced expiratory volume in one second (FEV1) to forced vital capacity (FVC), and in FEV1 as a percent of predicted associated with increased exposure to particles in nonsmoking young Polish men. While these studies looked at differences in PM exposure **between** communities, a study of the rate of lung function growth in children, using data from **within** city variations in Mexico City, reported reduced rates of growth associated with living in parts of the city with higher particle levels.

50. Again, a study that looks at differences in exposure over **time**, instead of over **space** is unlikely to be troubled by the confounders of a study looking at differences in exposure over space, and vice versa. This provides strong support for the causality of the association. A dramatic effect of such a change in exposure was seen by Avol and coworkers. They identified 110 children from the University of Southern California Children's Health Study who moved from the study area, and followed them in their new home with pulmonary function testing identical to that in the main cohort. Subjects who moved to locations with higher PM_{10} concentrations had lower rates of annual growth in lung function, while children who moved to

locations with lower PM_{10} levels than they had left showed higher rates of growth in lung function. This effect was increased in subjects who lived in the new location for at least three years.

51. A similar finding has been reported in adults. The Swiss Cohort Study on Air Pollution and Lung Diseases in Adults (SAPALDIA) is a prospective study of a random sample of adults in eight Swiss communities who were given lung function tests in 1991 and again in 2002. The initial study reported lower lung function in communities with higher particles, controlling for individual risk factors. The follow-up used sophisticated air dispersion models to estimate exposure at each person's address, accounting for any changes in address over the intervening 11 years. In analyses adjusted for town of origin, covariates, and baseline exposure, a decrease of 10 $\mu g/m^3$ in the average subject specific PM_{10} concentration between examinations was associated with a 9% decrease in the annual rate of decline in FEV_1 (i.e., by 3.1 ml/yr; 95% confidence interval (CI), 0.03 to 6.2), and a 16% decrease in the annual rate of decline in forced expiratory flow between 25% and 75% of volume out (FEF_{25-75}) (i.e., by 11.3 ml per second/yr; 95% CI, 4.3 to 18.2). This annual decrease in lung function is a strong predictor of survival—people whose lung function declines more rapidly as they age have a shorter life expectancy. Hence, these results are consistent with the finding that decreasing exposure results in increased life expectancy, reported earlier.

Respiratory Symptoms

52. I also find convincing evidence that long term exposure to particles is associated with increases in bronchitic symptoms, chronic cough, and other serious respiratory illnesses.

53. Dockery and coworkers, comparing symptom reports across six communities in the eastern United States with varying levels of pollution, and controlling for individual risk

factors, found that chronic bronchitis and chest illnesses in children were associated with exposure to particulate air pollution. No association was seen with asthma or wheezing.

54. Subsequent studies in the US and Europe confirmed that particle exposure across communities was associated with higher rates of chronic cough and bronchitis symptoms in children, and the lack of association with wheezing and asthma. For example, a large study (n=4,470) examined school children in 10 communities in Switzerland and reported an odds ratio for bronchitis of 2.88 (95% CI 1.69–4.89) for PM_{10} exposure between the most and least polluted community. That is, rates of bronchitis were almost 3 times as large in the highest PM community. The previously mentioned Southern-California-study examined 3,676 children across 12 communities and found that bronchitis was associated with PM_{10} , but only among children with asthma. The largest study was the Harvard-24-city-study, which examined 13,369 children. Particulate air pollution was associated with bronchitis episodes across these communities, controlling for individual risk factors.

55. Again, these studies have been complemented by studies examining **change** in pollution and **change** in symptom status. A follow-up of the Swiss children's study mentioned above reported that decreases in PM_{10} were associated with decreased respiratory symptom reporting in the 10 communities. Another recent follow-up of the SAPALDIA study reported that changes in PM_{10} exposure estimated at peoples' addresses was associated with changes in chronic respiratory symptoms during the 11 year follow-up. Similarly, declines in particle levels in East German towns following the collapse of communism were associated with declines in the rate of bronchitis and chronic cough in children.

56. Lending further credence to these reports is the study of Giroux and coworkers that contrasted exhaled NO (a marker of lung inflammation) in asthmatic children living in urban

areas with others staying in a national park in the mountains. They found the exhaled NO concentrations in the urban asthmatic children were more than double those in the asthmatic children in the national park, indicating that urban air pollution is associated with pulmonary inflammation.

57. Long term exposure to PM has also been associated with the development of chronic respiratory symptoms in adults. For example, I reported in 1993 that chronic pulmonary symptoms such as bronchitis were associated with long term exposure to air pollution in the NHANES II study adults[47]. Using data from the Seventh Day Adventist Study, a number of papers have reported associations between particle exposure and chronic respiratory symptoms, mostly recently using $PM_{2.5}$ as the exposure. Avino and coworkers also reported an association in a more limited two community study. An interesting case-control study by Karakatsani used in home examinations by physicians, including pulmonary function testing to confirm self reports of chronic respiratory conditions in adults, and in age and gender matched controls. A geographic model was used to assign individual exposure values, which were associated with the risk of chronic bronchitis and COPD.

Cognitive/neurotoxic effects

58. One of the most intriguing recent findings about particles is the report of Franco-Suglia et al. They used a geographic exposure model, calibrated to 82 different monitoring locations, to estimate the geographic variation of traffic particles in Boston (sulfate particles in Boston, coming primarily from the Midwest, are uniform in concentration across Boston, and hence could not be examined in this study). That does not mean the effects seen may not also occur with sulfate particle exposures. To date, the evidence for the toxicity of sulfate particles is as strong as for other particles. It is just that sulfate exposure was the same for all of the children

in the study, and so we could not examine the hypothesis). From this model, they estimated chronic exposure to traffic particles for school-aged children living in Boston. Higher particle exposure was associated with decrements in cognitive function of the order of 2 IQ points. Consistent with this, Rauh et al measured prenatal and post-natal exposure to ETS and Bayley Scales of infant development in 226 urban children enrolled during pregnancy and followed longitudinally. Prenatal ETS exposure (dichotomized as yes/no) predicted a 5 point decrement in the Bayley MDI scores($p=0.02$). Second hand smoke is enriched in combustion particles compared to primary tobacco exhaust, which has more gases. This is a major potential health hazard that requires confirmation. However, it does have some toxicological support.

59. Specifically, particles have been shown in experimental protocols to translocate from the nose up the olfactory nerve into the brain, with exposures shown not only in the olfactory bulb, but also in the striatum frontal cortex, and cerebellum. This in turn is associated with increased inflammatory responses in the brain, as well as changes in neurotransmitter levels. More recently, exposure to diesel exhaust has been shown to produce changes in electroencephalographic patterns in human volunteers, indicative of cortical stress. Calderon-Garciduenas and coworkers have produced a series of studies of small populations of children and dogs in Mexico City and a control, much less polluted Mexican city. They have reported that the dogs from Mexico City had greater rates of prefrontal lesions, neuroinflammation, gliosis, and particle deposition. MRI evaluation of the children's brains also revealed greater prefrontal lesions, and autopsy studies of accident victims showed upregulation of cyclooxygenase-2, ILb, and CD14 in victims living in more polluted locations.

60. Another study examined over 56,000 emergency admissions for severe Migraine attacks in Edmonton hospitals. Migraine is related to changes in brain cell receptors and neurotransmittors. Emergency visits were associated with $PM_{2.5}$ concentrations.

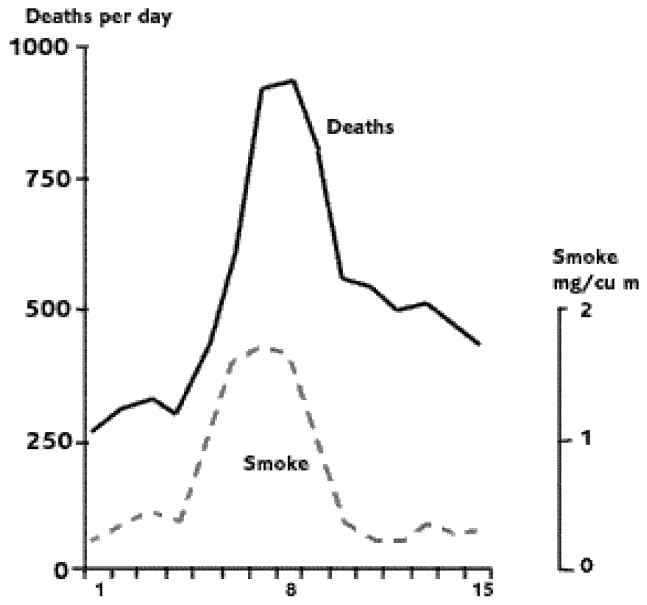
IV.b. Studies of Short Term Exposure

Mortality Studies

61. It is my opinion that airborne particles clearly are associated with increased deaths on the same and subsequent days. These results are confirmed by large numbers of studies.

62. The earliest and clearest studies of the effects of short-term changes in particles on mortality focused on severe air pollution episodes. Death counts for several days or weeks during and immediately after the episodes were compared to those before and after the event, or to the same dates in other years. These studies unambiguously showed that high concentrations of PM could increase death rates. For example, the figure below shows daily deaths and daily black smoke concentrations (produced by coal combustion) in London in the 1952 episode. As the month began a combination of weather fronts produced a sharp drop in wind speed, particularly over the southeast part of the country. On December 4 the wind velocity at the Kew Observatory in west London dropped from 6 knots at noon to 0 knots by 6pm. A low level thermal inversion combined with this to produce a rapid increase in particle concentrations. Deaths rose rapidly with the increase in particles. They also trailed off rapidly with the fall in particles, but while there was an initial rapid decline it had a slow tailing off and did not drop back to pre episode levels, but remained somewhat elevated for several weeks. This long tail of increased deaths after an episode has been reported in other episodes, and is consistent with the

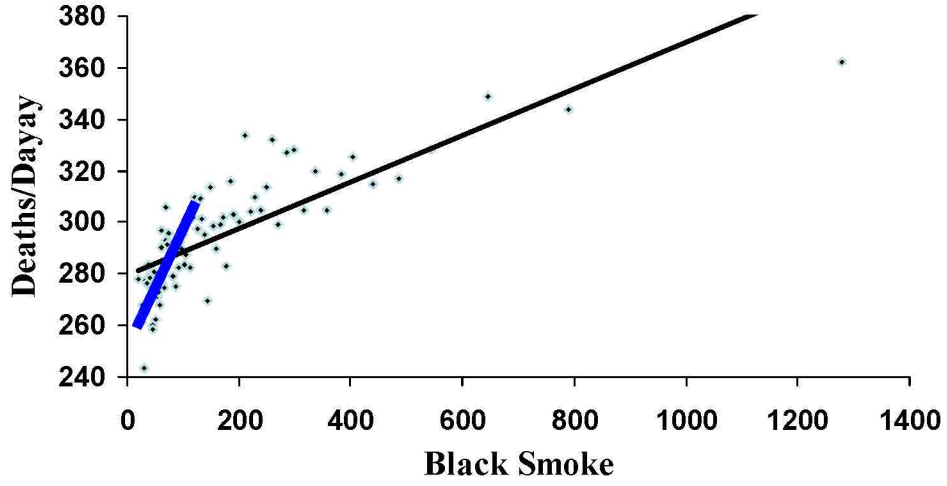
results of Zanobetti et al discussed above, where more usual particle exposure had an effect on mortality for weeks after the exposure.



63. This pattern was not due to influenza, because the epidemic did not hit Britain until about a month later. In the 160 Great Towns of England and Wales (excluding London) the weekly deaths changed from 4585 the preceding week to 4749 the week of the episode. The increase in pollution was far less in those towns, due to a lack of temperature inversions. Similar associations were reported in other episodes. By their nature, such studies do not tell us what happens at more usual exposures.

64. In the early 1990's the results of several daily time-series studies were reported. These studies did not rely on extreme pollution episodes, but evaluated changes in daily mortality counts associated with daily changes in air pollution at relatively low, more common

levels of pollution. For example, the below figure shows the average deaths in London and black smoke pollution from 14 winters (1958-71), as described by Schwartz and Marcus.



65. It clearly shows the association extends to as low as the pollution measurements, and that the slope relating daily deaths to particles is steeper at lower exposure levels. This result has been confirmed multiple times. Since this time, large multi-city studies of millions of deaths have confirmed that, controlling for season and weather, when airborne particles increase, daily deaths increase. This has been found in the United States, Europe, and Asia.

Case Crossover Studies

66. The case–crossover design, introduced by Maclure in 1991, is a method for investigating the acute effects of an exposure. In the case–crossover approach, a case–control study is conducted whereby each person who had an event is matched with him/herself on a nearby time period where s/he did not have the event. The subject's characteristics and exposures

at the time of the case event are compared with those of control periods in which the event did not occur. If exposure is related to the risk of an event, then we would expect, on average, higher exposure levels on the event days than on the control days. This approach has been applied to studying mortality effects of daily changes in particulate air pollution.

67. Applied to the association of air pollution with risk of death, the approach has several advantages. Because in this analysis each subject serves as his or her own control, the use of a nearby day as the control period means that all covariates that change slowly over time, such as smoking history, age, obesity, usual diet, diabetes, and so forth, are controlled for by matching.

68. The method also allows a more straightforward approach to seasonal control. Traditional methods involve Poisson regressions with smooth functions or regression splines to control for season. The case–crossover design controls automatically for seasonal variation, time trends, and confounders that vary slowly by time because the case and control periods are separated by a relatively small interval of time. That is, season and time trends are controlled by matching. Bateson and Schwartz demonstrated that by choosing control days close to event days, even very strong confounding of exposure by seasonal patterns could be controlled by design in the case–control approach. This makes the approach an attractive alternative to the Poisson models.

69. Once one has adopted the framework of choosing control days close to the event day for each subject, it is straightforward to extend this to control for a gaseous air pollutant. One can examine all of the potential control days that are close enough in time to each event day to control for seasonal confounding, and select the subset that also matches on the level of a gaseous co-pollutant. Since the day of death and control day for each decedent have the same

concentration of the other pollutant, the association between PM and death (from having on average higher PM on the day of death than the control day) cannot be alternatively explained by the other pollutant, since it is always the same on both days.

70. I applied this approach to a study of particulate air pollution and daily deaths in 14 U.S. cities. After matching, there were about 400,000 deaths in each analysis. PM_{10} was a significant predictor of mortality when controlling for gaseous air pollutants, with effect sizes ranging from a 0.45% increase in daily deaths per 10 $\mu g/m^3$ increment of PM_{10} [95% confidence interval (CI), 0.12–0.79%] when death and control days were matched ozone levels, to a 0.81% increase per 10 $\mu g/m^3$ increment of PM_{10} (95% CI, 0.47–1.16%) when matched on SO_2.

Confounding

71. There is convincing evidence that the association of particles with early death cannot be explained by confounding. This issue is the same for the studies of acute effects of particles as it is for the effects of longer term exposure—could some other factor, correlated with both exposure and mortality, explain the observed association? As noted above, the matching of case and control days by SO_2, NO_2, CO, and O_3 unambiguously showed that particles were associated with higher daily death rates in situations where those pollutants could not possibly be alternative explanations of the observed association, because they were the same on the day of death and control day. I did a similar study where the day of death and control day was matched by temperature, and again showed there was no confounding. Hence neither temperature nor other air pollutants can explain the observed association. Other studies using different methodologies have arrived at the same conclusion. For example, the NMMAPS study fit two pollutant models in the twenty largest US cities to estimate whether there were significant

associations independent of gaseous pollutants, and found that the association with particles was unchanged by control for gases. Another approach used a two stage hierarchical model to examine confounding by gaseous air pollutants. The basic idea of this approach is that since the relationship between particles and the putative confounder varies by city and season, if the observed particle effect is really due to the other air pollutant, its size should vary in the same way as that relationship between the particles and the confounder. It did not, confirming the lack of confounding by other pollutants.

72. Another possibility considered was confounding by respiratory epidemics. To examine this, Braga and coworkers analyzed daily deaths and PM in 5 U.S. cities in two ways. First they did the now classic Poisson time series analysis. Then, they used hospitalization data for pneumonia to identify each serious respiratory epidemic in each city. They fit 6th degree polynomials for each epidemic in each city to explain its rise and fall with time, and compared the association with particles to the original results. There were no changes in the association between daily PM and daily death with or without control for epidemics.

73. Another way to ensure an association is not explained by another air pollutant is to do it in a location and time where that other air pollutant is not present. For example, Fairley examined the association of particles and daily deaths in Santa Clara CA, in the winters. Since ozone is a summertime pollutant, ozone was essentially not present, and since sulfur containing fuels are not used in California, SO_2 levels were essentially non-existent. Yet similar associations with particles were seen as in other cites. Similarly, there is essentially no SO_2 in Provo Utah, where particles have been associated with daily deaths. Note that here we are talking about confounding by the direct effects of SO_2, not about its role as a precursor to sulfate particles. Similarly, the analysis of London winters could not have been confounded by ozone.

74. The recent report of Sarnat et al in Baltimore is also informative on the question of confounding. To argue that the effect of particles on mortality is really due to the fact that particle concentrations are correlated with, for example, SO_2 concentrations, makes an unspoken assumption. It assumes that particle concentrations measured at monitors in a city are related to personal exposure to particles, and that SO_2 concentrations are related to personal exposure to SO_2. Sarnat and coworkers used personal samplers that measured personal exposures to particles and these other pollutants in adults and children in the summer and winter to determine whether this was true. They found that personal exposures to particles and the particle concentrations at monitors were related. They also found that day-to-day variations in gaseous air pollutants measured at the central monitoring stations in the city **were not associated** with day-to-day changes in personal exposures to those gases. However, the monitored values of SO_2 and other gases *were* associated with day-to-day changes in personal exposure to $PM_{2.5}$. Hence, measurements of gaseous pollutants at central monitoring stations are not approximations of exposure to those gases. They are approximations of exposure to particles. In contrast, the measurements of particles at the central monitoring stations were correlated with personal exposure to particles. Hence ambient measurements of gases **may be alternative surrogates for exposures to particles and not measurements of confounders at all**. This indicates that studies of particles should not control for those gases.

75. Another recent personal exposure study examined the association between ambient measurements of temperature, personal exposure to temperature, and skin temperature in Baltimore. In this case, as well, ambient temperature was not correlated with either personal exposure to temperature or with skin temperature, indicating little potential for confounding.

This is not surprising. Adults in the U.S. spend over 95% of their time indoors, where space heating is ubiquitous and air conditioning common.

Threshold and Dose-Response

76. One special topic is whether there is a threshold in the association between PM and daily deaths. This has been addressed in a number of large multi-city studies. For example, I introduced an approach called meta-smoothing, to combine nonlinear dose-response curves across multiple studies. In simulation studies, I showed that it was capable of detecting a threshold, among other forms on nonlinearity, with good accuracy and no bias. This held true even with measurement error in exposure. I then applied it to a study of air pollution and daily deaths in 10 U.S. cities. The figure below is the result, showing no evidence of a threshold down to the lowest levels of PM_{10}.

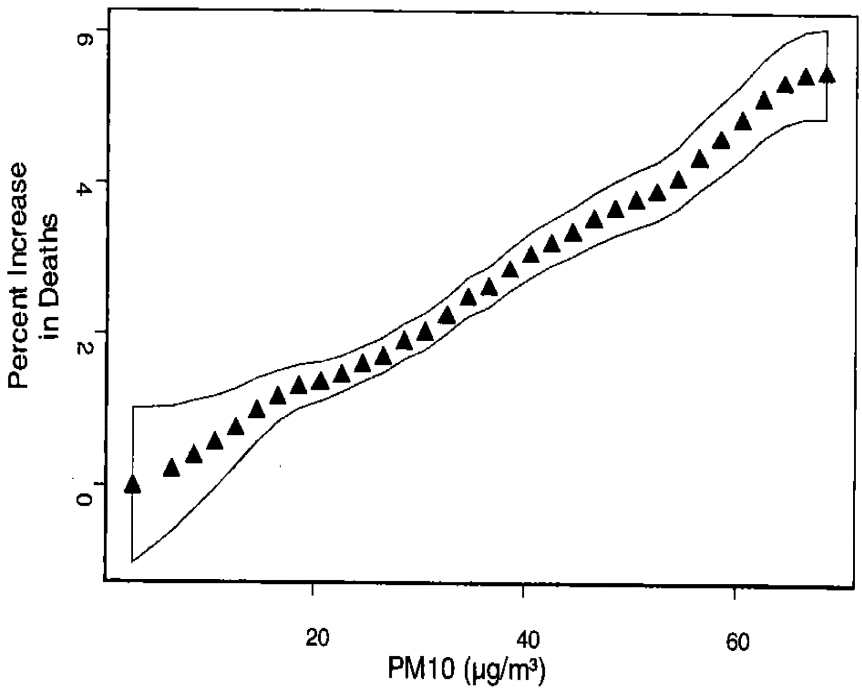
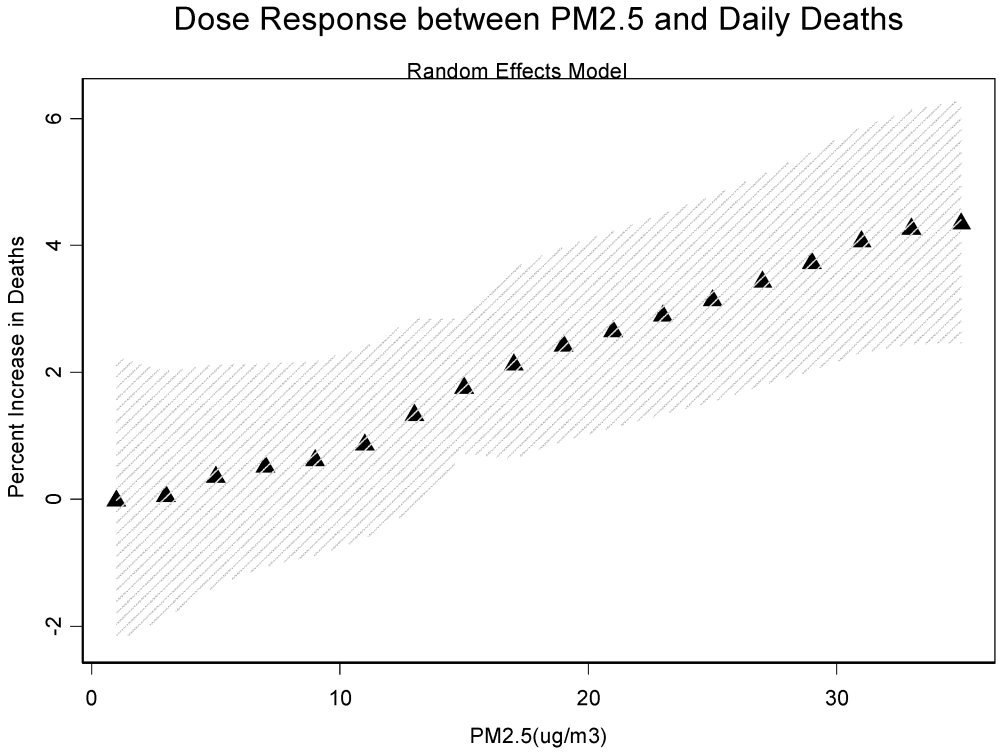


FIGURE 2. Dose response between PM_{10} and daily deaths in ten U.S. cities.

77. I also repeated this same analysis using $PM_{2.5}$ as the exposure, instead of PM_{10} in six U.S. cities where that data was then available. Those results are shown below. Note that essentially the entire dose-response curve takes place on days below the current ambient air quality standard.



Again, there have also been other approaches applied, again with the same conclusion .

Relationship with NAAQS

78. It is sometimes argued that by setting a National Ambient Air Quality Standard for particles EPA has explicitly determined that there are no adverse health effects at concentrations below that standard. EPA has explicitly rejected that interpretation. In its Regulatory Impact Analysis for the 1997 $PM_{2.5}$ standard EPA specifically rejected this view, stating that a NAAQS was not a "no effects" level. Specifically, they said, "The Act does not require the Administrator to establish a primary NAAQS at a zero-risk level". More recently, in its Regulatory Impact Analysis for the Clean Air Interstate Rule (2005) EPA stated that:

> The benefits estimates generated for the final CAIR are subject to a number of assumptions and uncertainties, which are discussed throughout this document. For example, key assumptions underlying the primary estimate for the mortality category include the following:
> 1) Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not yet been completely established, the weight of the available epidemiological and experimental evidence supports an assumption of causality.
> 2) All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM produced via transported precursors emitted from EGUs may differ significantly from direct PM released from automotive engines and other industrial sources. However, no clear scientific grounds exist for supporting differential effects estimates by particle type.
> 3) The C-R function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM, including both regions that are in attainment with the fine particle standard and those that do not meet the standard.

79. Similarly, in the EPA Particulate Matter Staff Paper (EPA, 2005) EPA concluded that, "it is appropriate to use the linear or log-linear concentration-response models reported in epidemiologic studies in the quantitative risk assessment" (p 3-59).

The staff paper was reviewed and approved by EPA's external Clean Air Scientific Advisory Committee.

80. EPA is joined in its conclusion that the dose-response relation is linear with no evidence of a threshold by the National Academy of Sciences, which in two reports endorsed such a conclusion, and its use in estimating the public health benefits of controlling air pollution. Thus, in 2002, the academy stated, "For pollutants such as PM_{10} and $PM_{2.5}$, there is no evidence for any departure of linearity in the observed range of exposure, nor any indication of a threshold" (NRC 2002).

81. This is also consistent with EPA's Expert Elicitation Report, where 11 out of 12 reviewers believed there was neither evidence nor a theoretical basis for a threshold. The remaining reviewer thought there was a 50% probability of a threshold, but that if it existed, there was an 80% probability that it was below 5 $\mu g/m^3$. There are no counties in downwind states of the Monroe plant where annual average concentrations get that low, rendering such a threshold moot.

Implications of a Linear Relationship

82. If, as the data indicate, and the scientific community believes, there is a linear dose-response between mortality and $PM_{2.5}$ concentrations, then any increase in particle concentrations in downwind communities of a coal burning powerplant will result in an increase in the death rate in those communities. While the increased rate will depend on the amount of increase in particle concentrations, and in some cases may be low, it will not be zero. Hence, there will be early deaths associated with such an increase, over time.

Importance of $PM_{2.5}$

83. A number of studies have documented greater effects of $PM_{2.5}$ on mortality than of coarse particles. Most recently, we examined the association between $PM_{2.5}$, coarse mass (the difference between PM_{10} and $PM_{2.5}$, representing particles with sizes between 2.5 and 10 μM), and daily deaths in 112 U.S. cities. We found each 10 $\mu g/m^3$ increase in particles was associated with a 1 % increase in daily deaths, while coarse mass was associated with about half that increase.

Mortality Displacement

84. If the deaths occurring after acute exposure to PM were only being brought forward by a few days, they would have much less public health significance. This issue was discussed in the section on Chronic Exposure effects, since the opposite appears to be true—the number of particle-associated deaths seems to rise with time after exposure, rather than being compensated for by a period of fewer than expected deaths. Hence this is not an issue. This seems to be because, in the image below, the effect of air pollution on recruitment into the Risk Pool is greater than its effect on dying out of the risk pool. Hence instead of depleting the pool, air pollution increases it, leaving more vulnerable people to die in subsequent days.

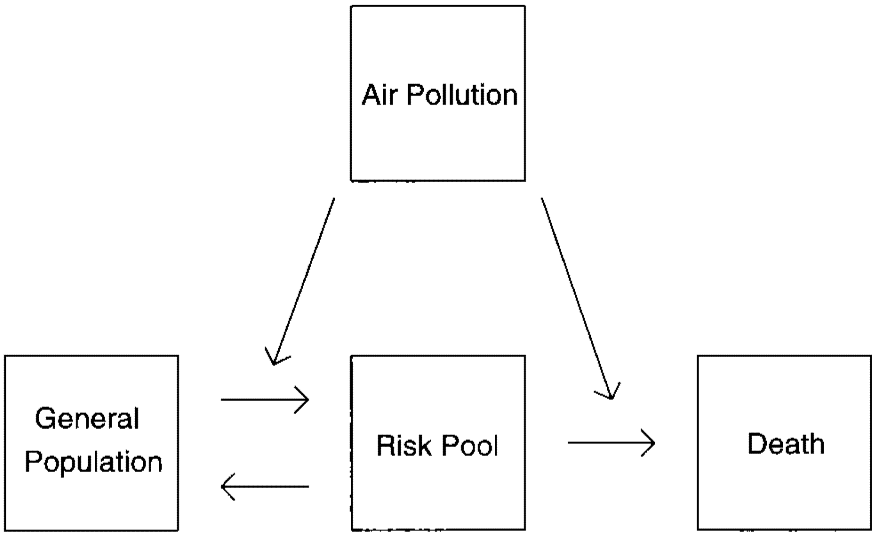


Fig. 1. The mechanics that lead to the mortality displacement.

Morbidity Studies

85. Particles in the air are not merely responsible for early deaths. They have a wide range of other heath effects, including triggering heart attacks, exacerbating respiratory infections to the point where the require hospitalization, triggering asthma attacks, etc. In the section below I briefly describe the evidence for some of these effects.

86. Hospital admission for heart disease and lung disease increase following increases in particles in the air. This has been demonstrated in numerous studies over the last several decades.

Respiratory Disease

87. Bates and Sizto first reported that sulfate particles from coal burning power plants were associated with hospital admissions for respiratory disease in Ontario back in the 1980's. Since that time, numerous studies have reported associations of particles and respiratory

admissions in Europe, the U.S. and Canada. These were followed by larger, multi-city studies that provided more stable estimates and made use of the same approaches described for the time series mortality studies to assure that associations were not confounded by other pollutants and temperature. In addition, several single city studies took advantage of special circumstances to rule out confounding. For example, I found that particles were associated with respiratory admissions in Spokane, WA, a town with essentially no SO_2, and where there was no correlation between particles and temperature, ruling those two out as potential confounders. I also showed that excluding very hot and very cold days, when one would expect the greatest effect of temperature, had no impact on the particle effects.

88. Hospital admissions for heart disease are also increased when particle concentrations go up. This is seen for all heart disease admissions, as well as for important categories of cardiovascular disease, such as heart attack, heart failure admissions, arrhythmia admissions, and strokes. For example, in a 1995 study in Detroit, I reported that heart attacks, as well as admissions for heart failure, increased as PM_{10} rose. Again, when I looked at a city where PM_{10} was essentially uncorrelated with SO_2 or Ozone, I found the same result. Studies such as these have again been followed by large multicity studies reporting associations with particles that are not confounded by other pollutants or weather.

Heart Attacks

89. The association of particles with an immediate increase in hospital admissions for heart attacks indicates that particles must be triggering the occurrence of heart attacks. There is considerable other evidence to suggest that is the case. First, studies have interviewed patients who survived heart attacks, and, using case-crossover analyses, found associations with particles.

Other focused studies had mixed results. However a large study of 21 U.S. cities definitively confirmed the association. A recent study examined emergency visits for acute coronary syndrome, essentially an early stage of a heart attack, and confirmed an association with particles (Lippi, 2009). Moreover, there is considerable toxicologic and mechanistic support for this effect. These are discussed below, under mechanistic studies.

Heart Failure

90. Heart failure is a serious disease where the heart's ability to pump blood to the body is impaired. Patients with heart failure have significantly reduced life expectancy, and episodes of increased impairment are dangerous, and frequently result in hospitalization. It is a large, growing, and expensive component of the nation's hospital burden. My study in 1995 identified increases in heart failure after increases in PM_{10} concentrations, indicating that particle exposure could cause an imbalance of the compensation that the body (with medication) makes for the poor pumping ability of the heart. Since then, those associations have been confirmed, including in large multi-city studies.

Stroke

91. The finding that particles increase strokes, a severely debilitating disease, was first reported in Asia. Recently, this has been confirmed in large multi-city studies in the U.S.. Interestingly, the association seems limited to ischemic strokes, not hemorrhagic strokes, which is consistent with the association with heart attacks.

IV.c. Mechanistic Studies

Oxidative Stress

92. Animal experiments indicate that reactive oxygen species (such as hydrogen peroxide, superoxide, etc), which have established relevance in the pathogenesis of cardiovascular disease and aging, are affected by particles, which represent one pathway for their cardiovascular and lung effects. For example, the figure below shows the increase in reactive oxygen species in animals within hours of exposure to concentrated particles from Boston air. Sulfate is one of the major contributors to Boston particles. Even more impressive, when animals who had been breathing Boston air (without concentration) were placed in a chamber where they could breathe filtered air, the concentrations of reactive oxygen species in the heart and lung fell by a third within days of removing the exposure (Figure 2). Moreover, it is evident from the figures that levels were still falling when the study was terminated.

Figure 1. Reactive oxygen species concentrations increase with PM Exposure

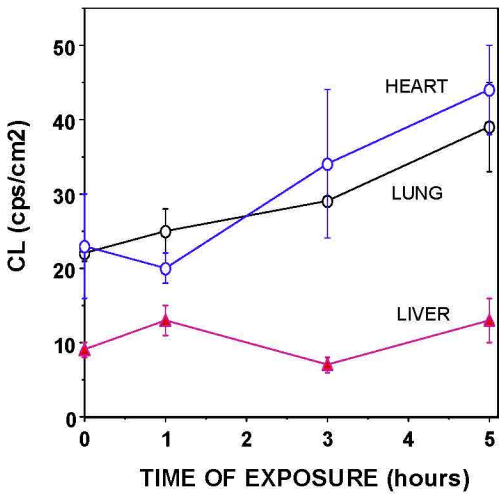
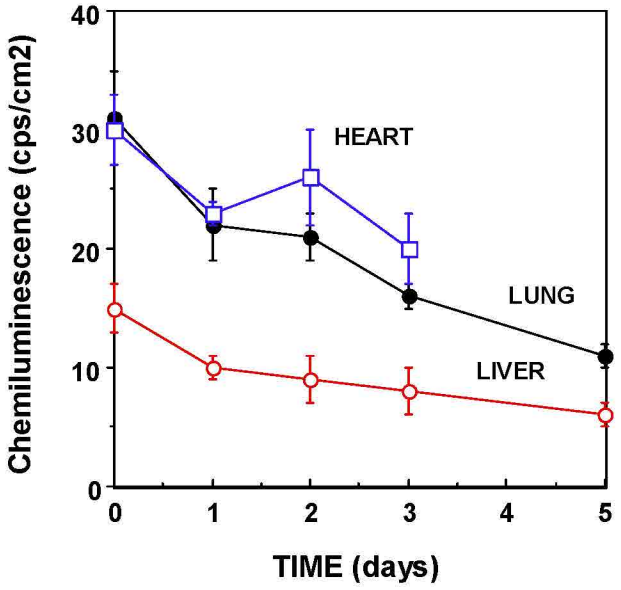


Figure 2. Reactive Oxygen Species decrease following removal of PM



93. Diesel particles have also been shown to increase oxidative stress in endothelial tissue, inducing the production of heme oxygenase-1, a rapid response part of the bodies defense system against oxidative stress. The viability of cell cultures of microvascular endothelial cells was impaired by diesel particles with an accompanying large increase in induction of heme oxygenase-1.

94. A series of studies have examined the role of genes related to oxidative stress on cardiovascular effects of particles, particularly heart rate variability (HRV). Schwartz and Chahine have reported that subjects that were missing the gene that makes glutathione S Transferase M1 (part of the defense against systemic oxidative stress), or with a variant of the *HMOX-1* gene that is less good at producing the antioxidant heme oxygenase, had larger effects

of particles on HRV, including a significant 3-way interaction. Other studies have focused on oxidative stress per se. For example, Rossner and colleagues examined bus drivers in Prague, and reported increased levels of indicators of oxidative stress such as F-2 isoprostane and 8-OHdG in drivers compared to controls.

Inflammation

95. Particles in the air have been shown to induce increases in inflammation in the lung, as well as systemically (which affects the heart). For example, exhaled NO is a marker for inflammation in the lung. Several studies have shown that particles increase exhaled NO in both children and the elderly. The urinary excretion of 8-hydroxy-2′-deoxyguanosine (8-OHdG) often has been used as a biomarker to assess the extent of repair of DNA damage (induced by inflammation and oxidative stress) in both the clinical and occupational setting. Particles, and particularly the metals on particles, have also been associated with an increased production of 8-OHdG, including specifically exposure to traffic pollution. 8-OHdG was also elevated in urban children compared to rural children.

96. CRP, ICAM-1, VCAM-1, and homocysteine are blood markers of the interrelated processes of inflammation and endothelial function, which play important roles in heart disease and atherosclerosis. Accordingly, CRP, ICAM-1, VCAM-1, and homocysteine have been shown to be independently and jointly associated with increased cardiac risk. In a prospective study of 28,263 healthy, post-menopausal women, for example, increased CRP and ICAM-1 were associated with increased risk of cardiac events. Correspondingly, elevated levels of ICAM-1 were associated with the development of accelerated atherosclerosis in a case-control study of 14,916 middle-aged men, while VCAM-1 predicted hospital events in angina patients[160]. Homocysteine, which inhibits NO release, has also been associated with coronary artery disease

measured radiographically and with flow mediated dilation. Hence examining these markers in response to air pollution is important. Particles have been shown to increase sICAM-1 and sVCAM-1 in diabetics, a finding confirmed in a controlled human exposure chamber study. Particles associations with CRP have been mixed in studies, but the effect may be limited to the obese or diabetics. Particles also increase homocysteine in the elderly.

97. Inflammation can also inhibit immune defenses against infections, and animals infected with Strep pneumonia and exposed to concentrated particles showed substantial worsening of the infection compared to control animals breathing filtered air.

Coagulation/Thrombosis pathway

98. Both animal and controlled human exposure studies have demonstrated that ambient particles can increase pro-thrombotic (i.e. clot forming) activity and even induce thrombosis in acute exposures. Thrombosis is associated with a range of adverse outcomes including embolisms, heart attacks, and, on a chronic basis, increased atherosclerosis. There is recent epidemiology that supports this finding. Baccarelli and coworkers reported an association of airborne particles with decreased clotting time, as well as the risk of deep vein thrombosis. This is consistent with the results of a controlled exposure study to Diesel particles, which reported increased ST depression (the depression of the ST segment of an electrocardiogram, which is a sign of ischemic heart disease) and alterations in fibrinolytic capacity (the ability to break up clots that have formed in blood vessels). Further support comes from a recent study of almost 58,000 women in the Women's Health Initiative. They found that $PM_{2.5}$ was associated with a 4% increase in the risk of an ST abnormality on the electrocardiogram and a 5% increase

in the risk of a T wave abnormaility (Zhang 2009). In addition, Kuenzli et al have reported an association of particle exposure with chronic atherosclerosis.

99. Suwa et al. have demonstrated that exposure to particles increases plaque formation and decreases plaque stability. Other studies have also indicated that enhanced throbosis in animals exposed to particles. Such changes increase the risk of a heart attack.

Ischemia

100. A number of studies have directly linked particle exposure with ischemia (reduced blood supply to the heart). Wellenius exposed dogs to either filtered air or concentrated air particles, followed by a temporary occlusion of the coronary artery. The animals exposed to particles experienced greater ischemia than those exposed to filtered air. Similarly, human volunteers exposed to particles manifested myocardial ischemia, and impaired ability to dissolve clots. And a follow-up study of a registry of patients who underwent coronary artery catherization in Utah found an association between particles and ischemic events. A standard measure of ischemia derived from electrocardiogram patterns is ST segment depression. Recent studies of subjects undergoing repeated examinations have found that particles are associated with increases in ST segment depression in vulnerable populations. This was also seen in human volunteers experimentally exposed to particles.

Blood Pressure Changes

101. Elevated blood pressure (BP) predicts cardiovascular morbidity and mortality, including heart attacks, and reductions in BP have been shown to reduce risk. Several studies have observed positive associations between ambient air pollutants and BP, although other

studies have failed to find associations or have even detected inverse associations between ambient air pollutants and BP.

102. There is evidence of both immediate effects and delayed effects over several days. Providing a mechanistic link relating particles to blood pressure, endothelin-1, which modulates systemic vascular tone, is known to increase in response to reactive oxygen species, which are elevated by particles (as noted above), and endothelin-1 has also been shown to increase directly in response to urban PM. Li and colleagues found that losartan, an antagonist of angiotensin II type 1 receptors, inhibits the vasoconstriction effect of urban particles on human pulmonary artery endothelial cells. In addition to its effects on blood pressure, angiotensin II is also a proinflammatory mediator, raising the possibility that the local renin–angiotensin system and systemic inflammation may be interrelated components of the cardiovascular system's response to ambient particles and the oxidative stress they induce.

103. Controlled human exposure studies have recently indicated that airborne particles are associated with acute changes in blood pressure. One study reported an association between arterial diameter and particle exposure. A follow-up study reported a direct association with blood pressure. This is supported by observational epidemiology studies in panels of subjects in Germany and the US. A more recent study (Wilker, 2009, looked at the change in blood pressure from sitting to standing, and found $PM_{2.5}$ was associated with these changes, and the effects were modified by genes related to pathways of blood pressure control. However the most exciting development in this field is one of the few uses of a randomized controlled trial in environmental epidemiology. McCracken and coworkers randomized houses in rural Guatemala that initially used unvented open fires for cooking to either receive a chimney stove (treatment group) or not (control group). Women over age 45 who cooked were examined in both groups, and a

significantly lower blood pressure was found in the intervention group[199]. At the end of the trial, the control group was given the same stove, and the investigators returned to measure blood pressure in the controls, using a pre-post design. Again, stove intervention was associated with a reduction in blood pressure.

Electrical control of the Heart

104. One potential pathway for the cardiovascular effects of particles is to change the autonomic nervous system, which affects both blood pressure, and the electrical control of the heart. The lung contains nerve endings from the autonomic nervous system, and stimulation or irritation of these nerve endings has been shown to have cardiovascular effects. One measure of such effects is from studies that have looked at repeated visits of subjects with electrocardiograms measured at each visit. Electrocardiogram changes in these studies have been related to particles in the air. Moreover, animal studies, and controlled human exposure studies, have confirmed such results. These studies are important because the types of electrocardiogram changes associated with particle exposure have been shown to increase the risk of death. Note that this applies to both short term and long term changes in these patterns.

Endothelial Pathway

105. The endothelium is the lining of the arteries, and it is not merely the coating of a tube carrying fluid. It is biologically active. When stressed, endothelial cells can activate clotting mechanisms, recruit inflammatory cells, which can disturb atherosclerotic plaques that have previously formed, and impair clot dissolving functions. Acutely, these can result in ruptures of the plaques, which trigger heart attacks; more chronically, it can result in atherosclerosis. Particles in the air affect these things. For example, Suwa and coworkers showed in animal

models that particles increase the rate of growth of plaques, and decrease stability—increasing the risk of a rupture. In general, indicators of endothelial dysfunction have been shown in epidemiologic, toxicologic, and controlled human exposures. These finding are quite consistent with the findings that particles are associated with heart attacks and sudden deaths.

106. Another recent study of mice genetically prone to atherosclerosis and on a high fat western diet exposed to concentrated particles from the outside air showed that the particle exposure lead to more atherosclerotic plaque, and increased macrophages and tissue factor in the plaques, which reduce plaque stability and increase the risk of a heart attack. An earlier study, in the northern suburbs of New York, where sulfates from coal burning power plants are a major fraction of the particles, again reported increased plaque and increased vasoconstriction in mice genetically prone to atherosclerosis. A more recent study, using a different mouse model of atherosclerosis documented that particle exposure increased oxidation of LDL (making it much more dangerous), increased the thickness of the arterial wall, and promoted plaque growth and instability. Yet, another study looked at gene expression in arterial tissue of animals following exposure to filtered air or particles. They reported clear signs of hundreds of genes changing their expression pattern after particle exposure, including increases in the inflammatory and cell proliferation (needed to thicken arterial walls and grow plaque) pathways.

V. SULFATES

107. While the association between exposure to particulate matter (PM) mass and mortality is well established, there remains uncertainty as to whether certain chemical components of PM are more harmful to human health than others. To date the evidence is not convincing that any form of fine combustion particles are more or less toxic than average, with

different studies showing different results. It is important to understand that the conclusion (of the Clean Air Scientific Advisory Committee and others) that we cannot differentiate the toxicity of different types or sources of particles does not mean that we believe it likely that one type of source of particles will ultimately prove to be the "toxic agent". Rather, the consensus scientific opinion is that all fine combustion particles are toxic, although they may vary in their toxicity. There have been time series studies in locations, such as Santa Clara, CA, in the winter, where wood smoke is the dominant source of particles, that show significant associations with daily deaths. There are studies in locations such as Philadelphia where secondary sulfate particles are the major source, which again show day to day changes in air pollution are associated with day to day changes in deaths. In Sao Paolo, Brazil, where traffic particles are the major sources, again, particles are associated with increased deaths. While we have not yet distinguished the relative effects of different sources of particles, it is clear that they all contribute to early deaths.

108. In the absence of good evidence that any source or type of particle had a *different* impact, CASAC recommended maintaining a standard for $PM_{2.5}$, that is, treating particles from all sources as having the *same* toxicity.

109. Sulfates are the principal particle type generated by coal burning power plants. Cohort studies such as the Six City Study and the ACS Cohort have reported that sulfates were associated with decreases in long term survival.

110. Sulfates have also been associated with increases in mortality in time series studies of acute exposure, including Mar et al who found increased total and cardiovascular mortality associated with a regional sulfate factor in Phoenix, suggesting that the impact of sulfates is not only an east coast phenomenon. While epidemiologic studies generally do not have the strength of an experimental design, the study of Pope and coworkers is an exception to

that rule. They looked at a natural experiment. A copper smelter strike in the Southwest between 15 July 1967 and early April 1968 shut down all the smelters in the region. During that period, smelters accounted for the large majority of the sulfate particles in these southwestern states. As reported by Trijonis and Yuan (1978) and Trijonis (1979) this strike led to significant reductions in sulfate particles in the Southwest, with an average decrease of 60% during the 8.5 month strike, which was equivalent to a reduction of approximately 2.5 $\mu g/m^3$ in mass concentration. This natural experiment really is equivalent to a randomized trial. The population of the downwind states had no choice in the matter—they were exposed to higher, lower, and higher sulfate concentrations over time, just as in a crossover trial for a drug. Nor did they even have a perception that their exposure was changed, since sulfate concentrations are not a routinely monitored criteria air pollutant, and there was little public attention to air pollution in this period.

111. Pope and coworkers analyzed this natural experiment to see how mortality rates change in response to the change in sulfate concentrations. After controlling for time trends, mortality counts in bordering states, and influenza/pneumonia deaths, they found that the 2.5 $\mu g/m^3$ decrease in sulfate particle concentrations resulted in a 2.5% decrease in the number of deaths in the four-state region. This unambiguously establishes secondary sulfate particles as a cause of early death.

112. In comparison, a 2.5 $\mu g/m^3$ decrease in long term average $PM_{2.5}$ concentrations in the American Cancer Society Cohort study was associated with about a 1.5% decrease in deaths, whereas in the Harvard Six City Cohort, the same decrease was associated with a 4% reduction in deaths. Hence this natural experiment not only shows that sulfate particles kill people, its effect size is consistent with the long term studies of mortality from following cohorts. This has two implications. First, it again suggests that there is no reason to believe that sulfate particles

are less toxic than average. Second, it shows that the reductions in mortality from reducing air pollution do not take years to show up, they occur within the first year. If additional reductions would have occurred in subsequent years, then this study underestimates the health benefits of reducing sulfate particle levels.

113. Although Schlesinger noted that many toxicological studies of simple artificially generated sulfate particles have not found a significant biological response, O'Neill et al found an association between real outdoor sulfate particles and endothelial dysfunction, and Chuang found sulfate increased oxidative stress and coagulation in a panel study. Sulfate particles were also associated with disturbances in electrocardiogram patterns in studies of repeated measurements in two different populations of elderly adults. The positive sulfate effects observed in epidemiological studies may be attributable to the greater complexity of the sulfate particles in ambient air than the simple ammonium sulfate often used in toxicological studies. For example, acid sulfate in the form of sulfuric acid or ammonium bisulfate can convert insoluble metal oxides (also present in ambient particulate pollution) to bio-available sulfate salts, and studies of particles collected in Washington DC have shown that much of the metal content was associated with sulfates. Metals on particles in turn have been linked to a wide variety of toxic responses. For example, toxicologic studies show Zinc sulfate to have cardiotoxicity. Other toxicologic studies have shown that sulfate particles produce lung inflammation and increased clotting factors in the blood.

114. Recently, Franklin and coworkers used data from the PM speciation network to examine this question further. Because particle components, including sulfates, were only monitored 1 day in 3 or 1 day in 6, while $PM_{2.5}$ was monitored daily, they used a two stage approach. Taking advantage of the natural variation in PM components between cities, and

between seasons within city, they fit season specific regressions in each of 25 cities with speciation monitors, in each season. In a second stage, they examined how the association between $PM_{2.5}$ and daily deaths was modified by the ratio of sulfate to particle mass, and similarly for the other measured components. If sulfates have a different toxicity than average for particles, then one would expect that a city where a high fraction of total particles were sulfate would have a different slope than a city with a low fraction. We found a significant overall effect of $PM_{2.5}$ with all cause mortality. Cities with high fractions of sulfate, arsenic (also a tracer of particles from coal burning power plants), silicon, and nickel had roughly twice the mortality slope as cities with low fractions. When multiple components were considered simultaneously, sulfate, nickel, and aluminum remained significant, and explained all of the apparent variation in effect estimates across cities and seasons.

115. A new analysis of the ACS study by Krewski and coworkers examined the extended follow-up period for the ACS, and looked at sulfate particles as well as all PM2.5 (Krewski D, Jerrett M, Burnett RT, et al. Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. Research report (Health Effects Institute) 2009(140):5-114; discussion 5-36.) Interestingly, they found a stronger effect for sulfates. They report that after controlling for the maximum number of individual and area based potential confounders the hazard ratios for sulfates were 1.045 if they used as exposure sulfate levels two years before the cohort was recruited, and 1.086 when they used sulfate levels from 1990, roughly the midpoint of the follow-up of the cohort. These hazard ratios were for a 5 μg/m3 increase in sulfate levels, and correspond to 9% and 17% increases in deaths per 10 $\mu g/m^3$ respectively.

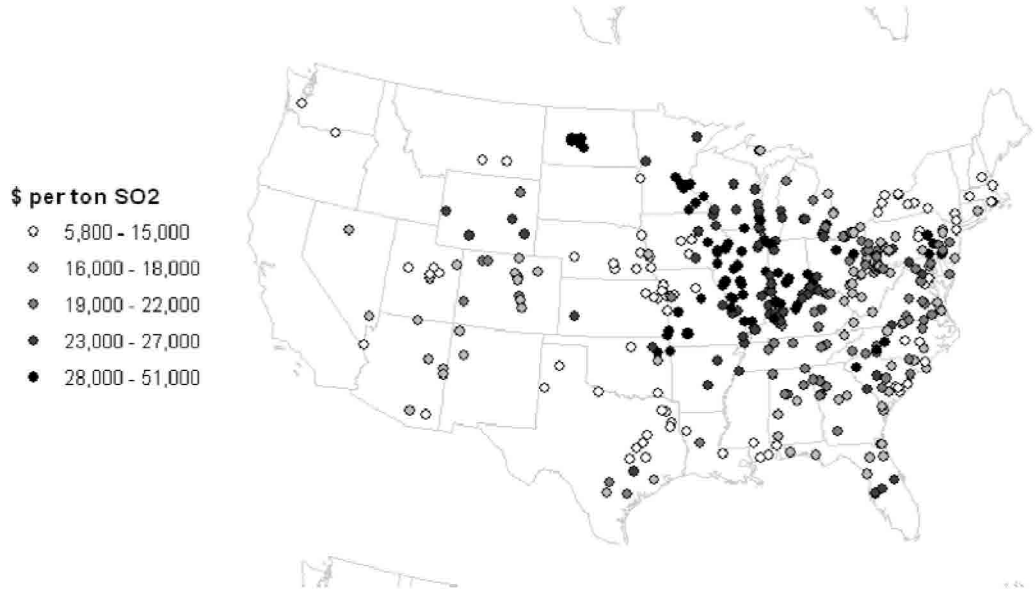
VI. QUANTITATIVE RISK ASSESSMENT

116. We have recently published a peer reviewed, quantitative risk assessment and benefit analysis for 407 coal burning power plants in the US (Levy 2009). We assessed the impact of emissions from 407 coal burning powerplants in the United States on health in every county of the United States, using emissions data for 1999. From that, we estimated the increase in deaths in each county, using the dose-response relationship from Schwartz (2008). We valued those deaths at the median of the estimates of a value of a statistical life, which we took to be $6 million per death.

117. This estimate is not really a price on a life. It is obtained by estimating how much people are willing to pay for small reductions in their risk of death, and converting. So if people are willing to pay $X for a reduction in risk of 1 in 10,000, than reducing risk in enough people to produce, on average, 1 fewer deaths would be worth 10,000 X dollars. This estimate is based on research where people are asked how much they would pay for consumer products that reduce risk or alternatively, examine how much more employers have to pay employees (adjusting for age, education, experience, etc) to compensate for taking an increased risk of accidental death.

118. To make these results more useful for policy purposes, we converted them into the costs per ton of SO_2 emitted, or alternatively, the cost per kilowatt hour of electricity produced. We also estimated uncertainties around these estimates, incorporating uncertainties for the modeled exposure estimates, uncertainties around the dose-response curve, and uncertainties in the value of a statistical life. A primary goal of our paper was to estimate how variable the damages from emissions were from plant to plant in the US. We found a median estimate of $19,000 per ton SO2 emitted, but substantial geographic variation. In general tons of SO2 emitted in Midwestern states caused more damage, since there was a greater population

downwind. This is shown in the figure below. Power plants in the Detroit area had particularly large damages per ton.



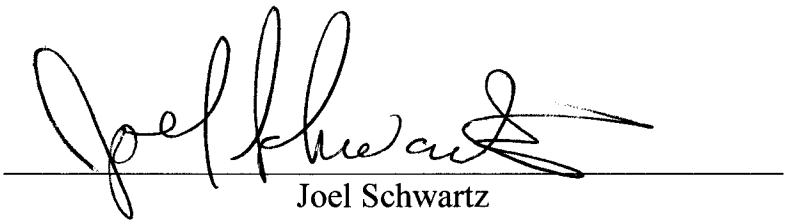
119. For NOX emissions the median damage per ton of emissions was $4,800, again with higher damages from the Industrial Midwest.

120. If we ignore the higher damages than average that likely result from emissions at the Monroe plant, we can estimate the total damage of the excess emissions using the median values. Using that conservative approach, and taking the annual excess emissions from Monroe 2 as 26,525 tons of SO2 and 7942 tons of NOX, then I project those emissions will result in $542 million in damages per year. This level of excess emissions would be expected to result in an additional 90 deaths per year in the downwind area. Thus eliminating that number of emissions would save 90 lives per year and save $542 million in social costs.

VII. CONCLUSIONS

121. In summary, particles in the air are associated with large numbers of deaths, heart attacks, hospitalizations for pneumonia, and other serious health impairments. There is no evidence for a threshold for these effects, which means that any incremental exposure is associated with incremental deaths, heart attacks, etc. in the general population. Coal burning power plants are a major source of these particles, and there is conflicting evidence on whether the particles from this source are more or less toxic than average, with the most recent data suggesting higher than average toxicity. Hence any emissions from these power plants caused serious harm to human health, including early deaths, and any reduction in emissions will have health benefits. Eliminating the excess emissions from this plant would result in approximately 90 fewer deaths per year in the exposed area, which, if this occurred in an occupational setting, would save an additional $540 million in wages to convince the workers to continue employment.

I declare under penalty of perjury that the foregoing is true and correct.



Joel Schwartz

Executed on July _21, 2010 in Boston, Massachusetts

ATTACHMENT A – CURRICULUM VITAE/RESUME AND LIST OF PUBLICATIONS

CURRICULUM VITAE

NAME:	JOEL SCHWARTZ
ADDRESS:	207 Lincoln Street, Newton Highlands, MA
PLACE OF BIRTH:	New York, New York
EDUCATION:	1969 B.A. Brandeis University
1980 Ph.D.	Brandeis University (Theoretical Physics)

ACADEMIC APPOINTMENTS:

2005 to present	Professor of Environmental Epidemiology, Harvard School of Public Health Director, Harvard Center for Risk Analysis
1994 -2004	Associate Professor of Environmental Epidemiology, HSPH
1994 - present	Associate Professor of Medicine, Harvard Medical School
1991-93	Lecturer, Department of Environmental Health, Harvard School of Public Health

HOSPITAL APPOINTMENTS:

1994 -	Associate Epidemiologist, Brigham and Women's Hospital

OTHER PROFESSIONAL POSITIONS AND MAJOR VISITING APPOINTMENTS:

1977-79	Legislative Assistant for Energy and Environment, Congressman Timothy Wirth
1979-87	Staff Scientist, U.S. Environmental Protection Agency
1987-88	Visiting Scientist, Department of Biostatistics, Harvard School of Public Health
1989, 94	Visiting Scientist, Department of Social and Preventive Medicine, University of Basel, Switzerland
1990	Visiting Scientist, Department of Occupational Safety and Environmental Health University of Wuppertal, Germany
1989-93	Senior Scientist, U.S. Environmental Protection Agency

HONORS AND DISTINCTIONS:

2008	John Goldsmith Award, International Society for Environmental Epidemiology Nichols Teaching Award, Harvard School of Public Health
2001	International Union of Environmental Protection Agencies World Congress Award
1999	Twentieth Century Distinguished Service Award, Lukacs Symposium for Statistical Ecology and Environmental Statistics
1991	John D and Catherine T MacArthur Fellowship
1984, 86	U.S. Environmental Protection Agency Silver Medal
1988, 89, 90, 92	U.S. Environmental Protection Agency Scientific Achievement
1991	Alumni Achievement Award, Brandeis University

MAJOR COMMITTEE ASSIGNMENTS:

National

1985	Preventing Lead Poisoning in Young Children document, Consultant, Centers for Disease Control
1988	Advisory Committee, Boston Soil Lead Study
1989-92	EPA Environmental Health Review Panel, Environmental Protection Agency
1989-93	National Academy of Science, Committee on Assessing Lead Exposure in Critical Populations
1990-93	National Academy of Science, Committee on Environmental Epidemiology
1992	Advisory Committee, Resources for the Future Center for Risk Management, Public Health/ Environmental Health Risk Studies
1992	Environmental Epidemiology Advisory Committee, Pew Memorial Trusts
1992	Ethics Committee, International Society for Environmental Epidemiology
1992	Reviewing Committee, Office of Technology Assessment for Identifying and Controlling Pulmonary Toxicants
1992-present	Technical Advisory Committee, Alliance to End Childhood Lead Poisoning
1992	Technical Advisory Committee, New York State Environmental Externalities Cost Study
1993	Subcommittee on Lead, National Advisory Committee on Environmental Policies and Technology
1993-present	Research Advisory Committee, National Center for Lead Safe Housing
1994-2002	Center for Disease Control, Advisory Committee on Childhood Lead Poisoning Prevention
1994-2005	Mickey Leland National Urban Air Toxic Research Center, Scientific Advisory Panel Environmental Statistics Subcommittee, National Advisory Committee on Environmental Policy and Technology
1998	Franklin Institute Science Medal Prize Committee
2003-2005	HSPH Disciplinary Committee
2004-present	Steering Committee, Harvard University Committee on the Environment
2005	EPA Science Advisory Board, Ad Hoc All Ages Lead Committee
2005-2008	Councilor, International Society for Environmental Epidemiology
2005-present	Editorial Board, American Journal of Respiratory and Critical Care Medicine
2005-2008	EPA Lead Clean Air Science Advisory Committee
2008-2009	EPA Board of Scientific Councilors, Human Health Subcommittee

International

1993-2004	European Economic Community Studies on Air Pollution, Daily Mortality, and Hospital Emergency Visits, Advisor
1993	Advisory Committee, European Economic Community Panel Studies Air Pollution, Pulmonary Function, and Respiratory Function
2000-2004	Chair, Statistics Advisory Committee, APHEIS Project

PROFESSIONAL SOCIETIES

1987	American Statistical Association
1988	American Thoracic Society
1990	Society for Epidemiologic Research
1991	International Society for Environmental Epidemiology

Editorial Board

	Epidemiology Editor, International Journal of Biometeorology
2005-present	Editorial Board, American Journal of Respiratory and Critical Care Medicine

MAJOR RESEARCH INTERESTS:

1. Respiratory Epidemiology
2. Air, Water and Lead Epidemiology
3. Epidemiologic Methods
4. Cost-Benefit Analysis

TEACHING EXPERIENCE:

1992	Environmental Epidemiology Course, University of Basel @ 30-40 Graduate Students 120 Preparation Time each year, 35 class hours
1994, 97, 99, 2009	Advanced Topics in Environmental Epidemiology, University of Basel, @ 20 Graduate Students, 35 class hours
1995	Short Course on Advanced Regression Analysis in Environmental Epidemiology, San Miniato, Italy @ 23 Graduate Students, 35 class hours
1996–present	Professor, ID 271 HSPH, joint course on Advanced Regression Analysis for Departments of Epidemiology, Environmental Health, and Biostatistics, 21 Graduate Students, 35 class hours
2007-present	Professor, EH520 Seminar on preparing research proposals
2007-present	Environmental Epidemiology, Cyprus International Institute
2009-present	Professor, Epi204-Analysis of Case Control and Cohort Studies
	European Course on methods for Poisson Time Series, Santorini Greece, @40 Graduate Students, 35 hours

	Short Course on Advanced Regression in Environmental Epidemiology, Annual meeting of International Society for Environmental Epidemiology, 45 Graduate Students, 7 hours
	European Course on methods of Meta-analysis. Santorini Greece, 40 students, 24 course hours
2006	Environmental Epidemiology, National Institute of Public Heath, Mexico 40 students 30 hours