STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENTAL QUALITY
LANSING

JENNIFER M. GRANHOLM
GOVERNOR

STEVEN E. CHESTER
DIRECTOR

July 16, 2007

Ms. Mary A. Gade, Regional Administrator
U.S. Environmental Protection Agency
Region 5
77 West Jackson Boulevard (R-19J)
Chicago, Illinois 60604-3507

Dear Administrator Gade:

Enclosed for your review is the submittal of the final rules packet as a revision to Michigan's State Implementation Plan (SIP) for the nitrogen oxides (NOx) requirements under the federal Clean Air Interstate Rule (CAIR). This packet includes the final rules, public hearing documents, and staff report. The Michigan Department of Environmental Quality (MDEQ) is requesting processing of these rules to facilitate the incorporation of the allocation methodologies and allowances as specified within our rules rather than the ones in the Federal Implementation Plan (FIP) under Title 40 of the Code of Federal Regulations (CFR), Part 97, Federal NOx Budget Trading Program and CAIR NOx and Sulfur Dioxide (SO_2) Trading Programs.

These rules were promulgated on June 25, 2007, and are being submitted under the abbreviated SIP provisions of the FIP for the CAIR NOx rules. The revision to Michigan's SIP for the promulgation of the CAIR SO_2 rules will be submitted under a separate cover letter, as that rule process is not expected to be finalized for several months.

This revision consists of modifications to Rule 803 and new Rules 802a, 821 through 826, and 830 through 834 of Michigan's Air Pollution Control Rules, promulgated pursuant to Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended. Rules 802a, 803, 821 through 826, and 830 through 834 are new NOx requirements, which complement the FIP under 40 CFR, Part 97. Also included in this revision are separate tables containing CAIR NOx allocations for affected CAIR NOx sources.

Michigan believes these rules will address the outstanding issue in the U.S. Environmental Protection Agency's (EPA's) Finding of Failure to Submit published in the *Federal Register* on April 25, 2005.

Pursuant to Section 110(a)(2)(D)(i) of the federal Clean Air Act regarding interstate transport of air pollutants, states are required to address four issues prohibiting sources or other activities located within the state from emitting any air pollutant that would:

1. Contribute to the nonattainment of the National Ambient Air Quality Standards (NAAQS) for areas in another state;
2. Interfere with the maintenance of the NAAQS by any other state;
3. Interfere with measures required to meet the implementation plan of any other state related to Prevention of Significant Deterioration; and
4. Interfere with measures required to protect visibility in any other state.

Michigan believes the submittal of the CAIR rules will address the first and second portions of the Section 110 requirements noted above. The third requirement above is addressed pursuant to Michigan's Air Pollution Control Rules, Part 2: Air Use Approval, which include provisions for new source review and permitting requirements. The fourth and final provision will be addressed with our submittal of a regional haze SIP in December 2007.

We appreciate your attention to this matter. If you have any questions regarding this submittal, please contact Mr. Robert Irvine, Air Quality Division (AQD), at 517-373-7042, or Ms. Teresa Walker, AQD, at 517-335-2247.

Sincerely,

Steven E. Chester
Director
517-373-7917

Enclosure
cc: Mr. Stephen Rothblatt, EPA
Mr. Doug Aburano, EPA
Mr. Jim Sygo, Deputy Director, MDEQ
Mr. G. Vinson Hellwig, MDEQ
Mr. Robert Irvine, MDEQ
Ms. Teresa Walker, MDEQ

Michigan Department of Environmental Quality
Air Quality Division

STATE IMPLEMENTATION PLAN SUBMITTAL

for

Part 8. Emission Limitations and Prohibitions -- Oxides of Nitrogen

R 336.1802a; R 336.1803; R 336.1821 through R 336.1826; and R 336.1830 through R 336.1834

Michigan Department of Environmental Quality
Air Quality Division
P.O. Box 30260
Lansing , MI 48909
http://www.michigan.gov/deqair

July 2, 2007

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COMPLETENESS REVIEW

Administrative Materials

1. A formal letter of submittal from the governor or designee requesting EPA approval of the revision.

Cover letter from G. Vinson Hellwig, Chief of the Air Quality Division, of the Michigan Department of Environmental Quality (MDEQ) to Ms. Mary Gade, Regional Administrator USEPA Region 5 requesting parallel processing of the SIP Revision

Cover letter from Steven Chester, Director of the Michigan Department of Environmental Quality (MDEQ) to Ms. Mary Gade, Regional Administrator USEPA Region 5 requesting approval of the SIP Revision

2. Evidence that the state has adopted the revision in the state code or body of regulations; or issued the permit, order, or consent agreement (hereafter document) in final form. That evidence should include the date of adoption or final issuance as well as the effective date of the revision if different from the adoption/issuance date.

Final from of adopted rules effective June 25, 2007, and the Secretary of State's Notice of Filing Administrative Rules (Attachment A)

Certification of adoption from MDEQ Director Chester (Attachment B)

Letter from MDEQ Director Chester to SOAHR Administrative Rules Manager, Norene Lind (Attachment B)

3. Evidence that the state has the necessary legal authority under state law to adopt and implement the revision.

Delegation of authority letter from Governor to USEPA Regions 5 (Attachment C)

SOAHR memo to MDEQ (Attachment D)

4. A copy of the actual regulation or document submitted for approval and incorporation by reference into the SIP, including indication of the changes made to the existing approved SIP, where applicable. The submittal should be a copy of the official state regulation/document signed, stamped, and dated by the appropriate state official indicating that it is fully enforceable by the state. The effective date of the regulation/document should, whenever possible, be indicated in the document itself.

Certificate of Approval by the Legislative Services Bureau (Attachment D)

Final form of adopted Rules (Attachment A)

5. Evidence that the state followed all of the requirements of its administrative procedures act (or equivalent) in conducting and completing the adoption/issuance of the revision.

SOAHR memo to MDEQ (Attachment D)

6. Evidence that public notice was given of the proposed change consistent with procedures approved by EPA, including date of publication of such notice.

The Agency Report (Attachment E) includes a copy of the DEQ Calendar notice of publication.

7. Certification that public hearings were held in accordance with the information provided in the public notice and the state's administrative procedures act (or equivalent), if applicable.

SOAHR Executive Director Plummer memo to the MDEQ (Attachment D)

The Public Hearing Record (Attachment F) includes the public hearing's opening statement with instructions.

8. Compilation of public comments and state's response thereto.

Summary of Comments and response are in Agency Report (Attachment E)

Technical Support

1. Identification of all regulated pollutants affected by the revision.

Oxides of Nitrogen

2. Identification of the location of affected sources including the EPA attainment/nonattainment designation of the locations and status of the attainment plans for the affected areas.

EGU and Non-EGU allocation tables (Attachment G)

The State of Michigan is currently in attainment for all criteria pollutants, except for the seven-county Metropolitan Statistical Area in Detroit which is nonattainment for particulate matter less than 2.5 microns.

ATTACHMENT A

STATE OF MICHIGAN
TERRI LYNN LAND, SECRETARY OF STATE
DEPARTMENT OF STATE
LANSING

June 25, 2007

NOTICE OF FILING
ADMINISTRATIVE RULES

To: Secretary of the Senate
Clerk of the House of Representatives
Joint Committee on Administrative Rules
State Office of Administrative Hearings and Rules 05-037-EQ
Legislative Service Bureau 07-06-02
Department of Environmental Quality

In accordance with the provisions of Section 46(1) of Act 306, Public Acts of 1969, as amended, and Executive Order 1995-6 this is to advise you that the Michigan Department of Labor & Economic Growth, State Office of Administrative Hearings and Rules filed at 4:38 P.M. this date, administrative rule (07-06-02) for the Department of Environmental Quality, Air Quality Division, Entitled *"Part 8. Emission of Oxides of Nitrogen from Stationary Sources."* These rules become effective immediately upon filing with the Secretary of State unless adopted under sections 33, 44, or 45a (6) of 1969 PA 306. Rules adopted under these sections become effective 7 days after filing with the Secretary of State.

Sincerely,

Terri Lynn Land
Secretary of State

Robin Houston

Robin Houston, Office Supervisor
Office of the Great Seal

Enclosure

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
AIR POLLUTION CONTROL

These rules were filed with Secretary of State on June 25, 2007

These rules become effective immediately upon filing with the Secretary of State unless adopted under sections 33, 44, or 45a(6) of 1969 PA 306. Rules adopted under these sections become effective 7 days after filing with the Secretary of State.

(By authority conferred on the director of the department of environmental quality by sections 5503 and 5512 of 1994 PA 451, MCL 324.5503 and 324.5512, and Executive Reorganization Order No. 1995-18, MCL 324.99903)

R 336.1803 is amended and R 336.1802a, R 336.1821, R 336.1822, R 336.1823, R 336.1824, R 336.1825, R 336.1826, R 336.1830, R 336.1831, R 336.1832, R 336.1833 and R 336.1834 are added to the Michigan Administrative Code, as follows:

PART 8. EMISSION LIMITATIONS AND PROHIBITIONS—
OXIDES OF NITROGEN

R 336.1802a Adoption by reference.

Rule 802a. The following documents are adopted by reference in these rules. Copies are available for inspection and purchase at the Air Quality Division, Department of Environmental Quality, 525 West Allegan Street, P.O. Box 30260, Lansing, Michigan 48909-7760, at the cost at the time of adoption of these rules (AQD price). Copies may be obtained from the Superintendent of Documents, Government Printing Office, P.O. Box 371954, Pittsburgh, Pennsylvania, 15250 7954, at the cost at the time of adoption of these rules (GPO price), or on the United States government printing office internet web site at http://www.gpoaccess.gov:

(a) Title 40 C.F.R., §72.2 definitions under the “Acid Rain Program General Provisions” (2006), AQD price $72.00; GPO price $62.00.

(b) Title 40 C.F.R. §72.8, “Retired Units Exemption” (2006), AQD price $72.00; GPO price $62.00

(c) Title 40 C.F.R., part 75, “Continuous Emission Monitoring” (2006), AQD price $72.00; GPO price $62.00.

(d) Title 40 C.F.R., §96.54, “Compliance” (2006), AQD price $70.00; GPO price $60.00.

(e) Title 40 C.F.R., §97.2, 97.102, 97.103, 97.302 and 97.303, definitions under the “Federal Oxides of Nitrogen (NOx) Budget Trading Program and CAIR NOx and Sulfur Dioxide (SO_2) Trading Programs” (2006), AQD price $70.00; GPO price $60.00.

(f) Title 40 C.F.R., §97.104, "Applicability" (2006), AQD price $70.00; GPO price $60.00.

(g) Title 40 C.F.R., §§97.180 to 97.188 and §§97.380 to 97.388, opt-in provisions under the "Federal Oxides of Nitrogen (NOx) Budget Trading Program and CAIR NOx and Sulfur Dioxide (SO_2) Trading Programs" (2006), AQD price $70.00; GPO price $60.00.

(h) Title 40 C.F.R., §97.304, Applicability (2006), AQD price $70.00; GPO price $60.00.

R 336.1803 Definitions.

Rule 803. (1) The provisions of 40 C.F.R. §96.2 are adopted by reference in this rule. The definitions for the oxides of nitrogen budget trading program in 40 C.F.R. §96.2 are applicable to R 336.1802 to R 336.1816. In addition, all of the following definitions apply as indicated, including a modification to the "NOx budget trading program" definition:

(a) "Electric-generating unit (EGU)" means the following:

(i) For units that commenced operation before January 1, 1997, a unit serving a generator during 1995 or 1996 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale.

(ii) For units that commenced operation on or after January 1, 1997, and before January 1, 1999, a unit serving a generator during 1997 or 1998 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale.

(iii) For units that commence operation on or after January 1, 1999, a unit serving a generator at any time that has a nameplate capacity of more than 25 megawatts and produces electricity for sale.

(b) "Large affected unit" means the following:

(i) For units that commenced operation before January 1, 1997, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1995 or 1996 a generator producing electricity for sale.

(ii) For units that commenced operation on or after January 1, 1997, and before January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1997 or 1998 a generator producing electricity for sale.

(iii) For units that commence operation on or after January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and to which either of the following provisions applies:

(A) The unit at no time serves a generator producing electricity for sale.

(B) The unit at any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of 25 megawatts or less and has the potential to use not more than 50% of the potential electrical output capacity of the unit.

(c) "Michigan fine grid zone" means the geographical area that includes all of the following counties:

(i) Allegan.

(ii) Barry.

(iii) Bay.

(iv) Berrien.
(v) Branch.
(vi) Calhoun.
(vii) Cass.
(viii) Clinton.
(ix) Eaton.
(x) Genesee.
(xi) Gratiot.
(xii) Hillsdale.
(xiii) Ingham.
(xiv) Ionia.
(xv) Isabella.
(xvi) Jackson.
(xvii) Kalamazoo.
(xviii) Kent.
(xix) Lapeer.
(xx) Lenawee.
(xxi) Livingston.
(xxii) Macomb.
(xxiii) Mecosta.
(xxiv) Midland.
(xxv) Monroe.
(xxvi) Montcalm.
(xxvii) Muskegon.
(xxviii) Newaygo.
(xxix) Oakland.
(xxx) Oceana.
(xxxi) Ottawa.
(xxxii) Saginaw.
(xxxiii) Saint Clair.
(xxxiv) Saint Joseph.
(xxxv) Sanilac.
(xxxvi) Shiawassee.
(xxxvii) Tuscola.
(xxxviii) Vanburen.
(xxxix) Washtenaw.
(xxxx) Wayne.

(d) "NOx budget trading program" means a multi-state nitrogen oxides air pollution control and emission reduction program established pursuant to 40 C.F.R. part 96 and part 97. The provisions of 40 C.F.R. part 96 and part 97 are adopted by reference in subrule (2) of this rule.

(e) "Ozone control period" means the period of May 31, 2004, through September 30, 2004, and the period of May 1 to September 30 each subsequent and prior year. The term "ozone control period" replaces the term "control period."

(2) For R 336.1803 through R 336.1816, the provisions of 40 C.F.R. part 96 and part 97 (2006) are adopted by reference, except as modified in R 336.1804,

R 336.1805, R 336.1808, R 336.1811, R 336.1813, and R 336.1815. Copies may be inspected at the Lansing office of the air quality division of the department of environmental quality. Copies of the regulations may be obtained from the Department of Environmental Quality, Air Quality Division, 525 West Allegan Street, P.O. Box 30260, Lansing, Michigan 48909-7760, at a cost as of the time of adoption of this rule of $70.00. A copy may also be obtained from the Superintendent of Documents, Government Printing Office, P.O. Box 371954, Pittsburgh, Pennsylvania 15250-7954, at a cost as of the time of adoption of this rule of $60.00; or on the United States government printing office internet web site at www.access.gpo.gov.

(3) Definitions under the clean air interstate rule NOx ozone season and annual trading programs in 40 C.F.R. §97.102 and §97.302 are applicable to R 336.1821 to R 336.1834. In addition, all of the following definitions apply as indicated:

(a) “Biomass” means wood, wood residue, and wood products (for example, trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal litter; vegetative agricultural, and silvicultural materials, such as logging residues (slash), nut and grain hulls, and chaff (for example, almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.

(b) “CAIR” means clean air interstate rule.

(c) “Commence commercial operation" means the following:

(i) For a unit not serving a generator producing electricity for sale, the unit's date of commencement of operation shall also be the unit's date of commencement of commercial operation.

(ii) For a unit with a date of commencement of operation as defined in this subrule and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(iii) For a unit with a date for commencement of operation as defined in this subrule and that is subsequently replaced by a unit at the same source (for example, repowered), such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in this subrule as appropriate.

(d) Electric generating unit or “EGU” means any of the following:

(i) For the purposes of the CAIR NOx ozone season trading program; a CAIR NOx ozone season unit as defined under 40 C.F.R. §97.304,

(ii) Electric generating units required to be in Michigan's NOx SIP budget trading program that are not already included under 40 C.F.R. §96.304, which are defined as:

(A) For units that commenced operation before January 1, 1997, a unit serving a generator during 1995 or 1996 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale.

(B) For units that commenced operation on or after January 1, 1997, and before January 1, 1999, a unit serving a generator during 1997 or 1998 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale.

(C) For units that commence operation on or after January 1, 1999, a unit serving a generator at any time that has a nameplate capacity of more than 25 megawatts and produces electricity for sale.

(iii) For purposes of the CAIR NOx annual trading program; a CAIR NOx unit as defined under 40 C.F.R. §97.104.

(e) "Existing EGUs" for allocation purposes under R 336.1821 to R 336.1834, means electric generating units that commenced operations prior to the most recent year of the 5-year period used to calculate the allocations pursuant to these rules.

(f) "Fossil fuel-fired," means as defined in 40 C.F.R. §97.2 for the purposes of determining applicability for units that are considered either of the following:

(i) EGUS as defined pursuant to R 336.1803(3)(d)(ii).

(ii) Non-EGUs as defined pursuant to R 336.1803(3)(k).

(g) "Fuel types," for the allocation of allowances under Michigan's programs only, means solid, liquid and gaseous fuel. The following definitions apply to fuel:

(i) "Solid fuel" includes, but is not limited to coal, biomass, tire-derived fuels and pet coke.

(ii) "Liquid fuel" includes, but is not limited to petroleum-based oils, glycerol, vegetable-based and animal waste-based liquids.

(iii) "Gaseous fuel" includes, but is not limited to coke oven gas, natural gas, propane, coal gas, blast furnace gas, and methane derived from animal wastes.

(h) "Michigan fine grid zone" means the geographical area that includes all of the following counties:

(i) Allegan.

(ii) Barry.

(iii) Bay.

(iv) Berrien.

(v) Branch.

(vi) Calhoun.

(vii) Cass.

(viii) Clinton.

(ix) Eaton.

(x) Genesee.

(xi) Gratiot.

(xii) Hillsdale.

(xiii) Ingham.

(xiv) Ionia.

(xv) Isabella.

(xvi) Jackson.

(xvii) Kalamazoo.

(xviii) Kent.

(xix) Lapeer.

(xx) Lenawee.

(xxi) Livingston.

(xxii) Macomb.

(xxiii) Mecosta.

(xxiv) Midland.

(xxv) Monroe.
(xxvi) Montcalm.
(xxvii) Muskegon.
(xxviii) Newaygo.
(xxix) Oakland.
(xxx) Oceana.
(xxxi) Ottawa.
(xxxii) Saginaw.
(xxxiii) Saint Clair.
(xxxiv) Saint Joseph.
(xxxv) Sanilac.
(xxxvi) Shiawassee.
(xxxvii) Tuscola.
(xxxviii) Vanburen.
(xxxix) Washtenaw.
(xxxx) Wayne.

(i) "New EGUs," for allocation purposes under R 336.1821 to R 336.1834, means electric generating units that are commencing operation or projected to commence operation on or after January 1 of the most recent year of the 5-year period used to calculate the allocations pursuant to these rules.

(j) "Newly-affected EGUs," for allocation purposes under R 336.1821 to R 336.1834, means existing EGUs located outside the Michigan fine grid zone or existing EGUs located within the Michigan fine grid zone which were exempt from the federal NOx budget program. This definition is applicable for the 2009 CAIR NOx ozone season program only and after that time the newly affected EGUs are considered existing EGUs. This definition excludes the Harbor Beach power plant which was previously included as an EGU in the NOx SIP Budget trading program and is considered existing for the purposes of CAIR NOx ozone season program.

(k) "Non-EGUs" means the following units located in Michigan's fine grid zone:

(i) For units that commenced operation before January 1, 1997, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1995 or 1996 a generator producing electricity for sale.

(ii) For units that commenced operation on or after January 1, 1997, and before January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1997 or 1998 a generator producing electricity for sale.

(iii) For units that commence operation on or after January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and to which either of the following provisions applies:

(A) The unit at no time serves a generator producing electricity for sale.

(B) The unit at any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of 25 megawatts or less and has the potential to use not more than 50% of the potential electrical output capacity of the unit.

(l) "Ozone Season" means May 1 to September 30 of each calendar year.

(m) "Renewable energy source," for allocation purposes under R 336.1821 to R 336.1826, means a source, located in Michigan, that generates electricity by solar, wind, geothermal, or hydroelectric processes, excluding nuclear, that has commenced operation or is projected to commence operation on or after January 1 of the most recent year of the 5-year period used to calculate the allocations pursuant to these rules, which meets all of the following:

(i) Serves a generator at 25 megawatts or greater of electrical output.

(ii) Is not subject to R 336.1801(4)(a) or covered by any other definitions in this rule.

(iii) Captures energy from on-going natural processes.

(iv) Is considered a non-emitting, having zero emissions, source.

(n) "Renewable energy projects," for allocation purposes under R 336.1821 to R 336.1826, means renewable energy sources, located in Michigan and located within the same geographic area that when added together equal a generator greater than 25 megawatts of electrical output.

(o) "Unit" means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system, pursuant to EGUs as defined under R 336.1803(3)(d)(ii) and non-EGUs as defined under R 336.1803(3)(k).

R 336.1821 CAIR NOx ozone season and annual trading programs; applicability determinations.

Rule 821. (1) This rule establishes Michigan's CAIR ozone season and annual emission budgets and trading programs for all of the following units:

(a) CAIR NOx units as defined pursuant to 40 C.F.R. §97.104, adopted by reference in R 336.1802a.

(b) CAIR NOx ozone season units as defined pursuant to 40 C.F.R §97.304, adopted by reference in R 336.1802a.

(c) All units required to be in the state's NOx SIP call trading program that are not already included under 40 C.F.R. §97.304 and are defined in R 336.1803(3)(d)(ii) and (k).

(d) For purposes of allocating allowances under R 336.1821 to R 336.1826, the following units which are not addressed in subparagraphs (a), (b) and (c) of this subrule are CAIR NOx ozone season units:

(i) Renewable energy sources.

(ii) Renewable energy projects.

(2) An EGU located in Michigan and subject to the requirements pursuant to R 336.1821(a), (b) or (c) shall apply for and receive an annual or ozone season CAIR NOx permit. In addition, non-EGUs as defined in R 336.1803(3)(k) shall apply for and receive an ozone season CAIR NOx permit. This permit shall be administered under R 336.1214 and shall be incorporated into the source's renewable operating permit as an attachment. A federally enforceable NOx budget permit issued under the federal NOx budget program pursuant to R 336.1808 shall remain in effect until the CAIR NOx ozone season permit has been approved by the department.

(3) The fuel type adjusted allocations for each existing EGU shall be determined by multiplying the appropriate NOx emission rate and heat input as determined in

accordance with R 336.1822 and R 336.1830 with an appropriate fuel adjustment factor coefficient as follows:

(a) For a solid fuel-fired EGU, the allocation calculations shall be adjusted by multiplying the allocation values by 100%, i.e. 1.0.

(b) For a liquid fuel-fired EGU, the allocation calculations shall be adjusted by multiplying the allocation values by 60%, i.e. 0.60.

(c) For a gaseous fuel-fired EGU, the allocation calculations shall be adjusted by multiplying the allocation values by 40%, i.e. 0.40.

(d) For a multi-fueled EGU, the allocation adjustment calculation shall be a weighted average based on the percentage heat input from each type of fuel burned in the unit, unless the source can demonstrate that certain types of fuel used in the process provided less than 10% of the annual heat input. If so, then the allocation adjustment is calculated based on only those fuel types which contributed 10% or more of the annual heat input.

(4) The owner or operator of any CAIR NOx ozone season or annual unit shall submit all of the following data within 30 days upon request by the department:

(a) A unit's ozone season and annual heat input values or megawatt energy produced, which shall be the same data reported in accordance with 40 C.F.R. part 75 to the extent the unit is subject to 40 C.F.R. part 75 for the period involved.

(b) A unit's total tons of oxides of nitrogen emissions during specified calendar years or ozone seasons as determined under 40 C.F.R. part 75, adopted by reference in R 336.1802a.

(5) Effective January 1, 2009, the provisions of R 336.1802, R 336.1803(1) and R 336.1803(2), R 336.1804, R 336.1805, R 336.1806, R 336.1807, R 336.1808, R 336.1809, R 336.1810, R 336.1811, R 336.1812, R 336.1813, R 336.1814, R 336.1815, and R 336.1816 shall not apply to the control period beginning in 2009 or any control period thereafter.

(6) Pursuant to the provisions in 40 C.F.R. §96.54 and for the 2009 control period only, if the U.S. environmental protection agency determines that there were excess emissions during the 2008 control period, deductions for excessive emission penalties shall be taken from the 2009 CAIR NOx ozone season allowances. Title 40 C.F.R. §96.54 is adopted by reference in R 336.1802a.

(7) Pursuant to any NOx SIP unused set-aside allowances through 2008 that are accumulated within the state account, the department shall allocate these allowances according to R 336.1823.

R 336.1822 CAIR NOx ozone season trading program; allowance allocations.

Rule 822. (1) The CAIR NOx ozone season trading program budget allocated by the department under subrule (3) of this rule for the CAIR NOx ozone season control periods to the EGUs, non-EGUs, and renewable energy sources shall annually equal the total number of tons of oxides of nitrogen emissions as indicated in the following manner:

(a) The total CAIR NOx ozone season budget for the ozone season time period of 2010 to 2014 is 31,180 tons. These allocations shall be distributed as follows:

(i) The CAIR NOx ozone season budget available to existing and newly-affected EGUs. The following applies:

(A) For 2010 and 2011 ozone season control periods equals 28,321 tons.
(B) For 2012 to 2014 ozone season control periods equals 28,021 tons.
(ii) The CAIR NOx ozone season budget available to existing non-EGUs for the 2010 to 2014 ozone season control periods is 1,309 tons.
(iii) The CAIR NOx ozone season budget available to new non-EGUs and EGUs. The following applies:
(A) For 2010 and 2011 ozone season control periods is 700 tons.
(B) For 2012 to 2014 ozone season control periods is 1,000 tons.
(iv) The CAIR NOx ozone season budget available to renewable energy sources and projects in the 2010 to 2014 ozone season control periods is 200 tons.
(v) The CAIR NOx ozone season budget available to all existing EGUs and non-EGUs that have submitted an acceptable demonstration of a hardship to the department, in the 2010 to 2014 ozone season control periods is 650 tons.
(b) The total CAIR NOx ozone season budget for the ozone season time period of 2015 and thereafter is 26,351 tons. These allocations shall be distributed as follows:
(i) The CAIR NOx ozone season budget available to existing EGUs in the 2015 and thereafter ozone season control periods is 22,792 tons.
(ii) The CAIR NOx ozone season budget available to existing ozone season non-EGUs for the 2015 and thereafter ozone season control periods is 1,309 tons.
(iii) The CAIR NOx ozone season budget available to new non-EGUs and EGUs in the 2015 and thereafter ozone season control periods is 1,400 tons.
(iv) The CAIR NOx ozone season budget available to renewable energy sources and projects in the 2015 and thereafter ozone season control periods is 200 tons.
(v) The CAIR NOx ozone season budget available to all existing EGUs and non-EGUs that have submitted an acceptable demonstration of hardship to the department, in the 2015 and thereafter ozone season control periods is 650 tons.
(2) CAIR NOx allowances for the 2009 ozone season control period shall be the same allowances as were allocated under the NOx budget trading program. For newly-affected EGUs which were not subject to the federal NOx budget program, these units are eligible to apply for allowances from the CAIR NOx ozone season new source set-aside pool for the 2009 ozone season, pursuant to R 336.1823.
(3) The department shall allocate CAIR NOx ozone season allowances to existing EGUs and non-EGU ozone season units for calendar years 2010 and thereafter according to the following schedule:
(a) A 3-year allocation that is 3 years in advance of the 2010 ozone season and 4 years in advance of each subsequent ozone season control period. The 3-year allocation shall be as follows:
(i) By 60 days after the effective date of this rule or April 30, 2007, whichever is earlier, the department shall submit to the U.S. environmental protection agency the CAIR NOx ozone season allowance allocations, under this subrule, for the ozone season control periods in 2010 and 2011.
(ii) By October 31, 2008, the department shall submit to the U.S. environmental protection agency the CAIR NOx ozone season allowance allocations, under this subrule, for the ozone season control periods in 2012, 2013, and 2014.
(iii) By October 31, 2011, and thereafter each October 31 of the year that is 3 years after the last year of allocation submittal, the department shall submit to the

U.S. environmental protection agency the CAIR NOx ozone season allowance allocations as indicated under this subrule.

(4) For the CAIR NOx ozone season control periods under subrule (3) of this rule, the department shall allocate allowances to existing EGU and non-EGU ozone season units that commenced operation before January 1 of the most recent year of the 5-year period used to calculate heat input as follows:

(a) The department shall allocate allowances to each existing EGU ozone season unit as follows:

(i) During calendar years 2010 to 2014 as follows:

(A) Units with an allowable NOx emission rate equal to or greater than the CAIR target budget rate of 0.15 pounds per million Btu, and units with no applicable NOx emission rate shall receive an initial unadjusted allocation of allowances in an amount equaling 0.15 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(B) Units with an allowable NOx emission rate less than the CAIR target budget rate of 0.15 pounds per million Btu shall receive an initial unadjusted allocation of allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

$$Allocation = \left[\frac{\left\{ \frac{(CTER \ x \, FAF) + AER}{2} \right\} x \ HI}{2000 \, lb / ton} \right]$$

Where:

Allocation =	The initial unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2009 to 2014 of 0.15 pounds per mm Btu.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate.
HI =	Average of the unit's 2 highest heat inputs in mm Btu for the appropriate 5 control periods.

(ii) During calendar years 2015 and thereafter as follows:

(A) Units with an allowable emission rate equal to or greater than the CAIR target budget rate of 0.125 pounds per million Btu shall receive allowances in an amount equaling 0.125 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(B) Units with an allowable emission rate less than the CAIR target budget rate of 0.125 pounds per million Btu shall receive allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

$$Allocation = \left[\frac{\left\{ \frac{(CTER \ x \ FAF) + AER}{2} \right\} x \ HI}{2000 lb / ton} \right]$$

Where:

Allocation =	The initial unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2015 and thereafter of 0.125 pounds per mm Btu.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate.
HI =	Average of the unit's 2 highest heat inputs in mm Btu for the appropriate 5 control periods.

(b) The department shall allocate allowances to each existing non-EGU ozone season unit for calendar years 2010 to 2015 and thereafter in an amount equaling 0.17 pounds per million Btu or the allowable emission rate, whichever is more stringent, multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(5) If the initial total number of CAIR NOx ozone season budget allowances allocated to either all existing EGU or all existing non-EGU ozone season units for the years under subrule (4) of this rule does not equal the budgeted tons for such units as specified in subrule (1) of this rule, then the department shall adjust up or down the total number of CAIR NOx ozone season budget allowances allocated to each existing EGU or non-EGU, as appropriate, so that the total number of CAIR NOx ozone season budget allowances allocated to the entire group of EGUs or non-EGUs equals the appropriate values in subrule (1) of this rule. The adjustment shall be made by multiplying each unit's unadjusted initial allocation by a correction factor determined by dividing the appropriate existing EGU or non-EGU total budget tons from subrule (1) of this rule by the sum of all existing EGU or non-EGU units' initial unadjusted allocations, and rounding to the nearest whole number, as appropriate.

(6) The heat input, in million Btu's, used for calculating oxides of nitrogen allowance allocations for each subject unit under this rule shall be the unit's average of the 2 highest heat inputs for the ozone season control period in the 5 years immediately preceding the year in which the department is required to submit the oxide of nitrogen allocations. If the unit operated less than 2 full ozone seasons of the 5-year time period, then the unit's single highest ozone season heat input shall be used.

R 336.1823 New EGUs, new non-EGUs, and newly-affected EGUs under CAIR NOx ozone season trading program; allowance allocations.

Rule 823. (1) The department shall establish a set-aside pool for each CAIR NOx ozone season control allocation year for new EGUs and non-EGUs. This set-aside pool shall be allocated on a yearly basis as follows:

(a) For 2009, a total of 1,385 tons of CAIR NOx ozone season allowances, which have been carried over from the federal NOx budget program, for any new and newly-affected EGUs or new non-EGUs.

(b) For years 2010 and 2011, a total of 700 tons of CAIR NOx ozone season allowances for any new EGUs or new non-EGUs.

(c) For years 2012 to 2014 ozone season control periods, a total of 1,000 tons of CAIR NOx ozone season allowances for any new EGUs or new non-EGUs.

(d) For years 2015 and thereafter, a total of 1,400 tons of CAIR NOx ozone season allowances for any new EGUs or new non-EGUs.

(2) The CAIR authorized account representative of a newly-affected CAIR NOx ozone season EGU under this rule may submit to the department a request, in a format specified by the department, to receive CAIR NOx ozone season allowances for the 2009 CAIR NOx ozone season control period. All of the following apply:

(a) The oxides of nitrogen allowance allocation request shall be submitted before March 1 of the 2009 ozone season control period.

(b) The CAIR authorized account representative of any newly-affected EGU may request 2009 CAIR NOx ozone season allowances, based on an amount equaling 0.15 pounds per million Btu multiplied by the unit’s ozone season heat input, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(c) The heat input, in million Btu's, used for calculating oxides of nitrogen allowance allocations for each subject unit under this rule shall be the unit's average of the 2 highest heat inputs for the ozone season control period in the 5 years immediately preceding the year in which the department is required to submit the oxide of nitrogen allocations. If the unit operated less than 2 full ozone seasons of the 5-year time period, then the unit's single highest heat input shall be used.

(3) The CAIR authorized account representative of a new CAIR NOx ozone season non-EGU under this rule may submit to the department a request, in a format specified by the department, to receive CAIR NOx ozone season allowances starting with the ozone season control period during which the CAIR NOx ozone season unit commenced or is projected to commence operation and ending with the control period preceding the control period for which it shall receive an allocation under R 336.1822. Both of the following apply:

(a) The CAIR NOx ozone season allowance allocation request shall be submitted before March 1 of the year of the first ozone control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the non-EGU, if required, and each following year by March 1.

(b) The CAIR authorized account representative of any new non-EGU may request CAIR NOx ozone season allowances, based on an amount equaling 0.17 pounds per million Btu or the allowable emission rate, whichever is more stringent, multiplied by the nameplate design heat input rate for the unit, in million Btu's per hour, multiplied by the predicted hours of operation for the control period, divided by 2,000 pounds per ton and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(4) The CAIR authorized account representative of a new EGU CAIR NOx ozone season unit under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx ozone season allowances, starting with the ozone season control period during which the CAIR NOx ozone season unit commenced or is projected to commence operation and ending with the control period preceding the control period for which it shall receive an allocation under R 336.1822. All of the following apply:

(a) The CAIR NOx ozone season allowance allocation request shall be submitted before March 1 of the year of the first ozone control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the EGU, if required, and each following year by March 1.

(b) The allocation methodology used for the first ozone season for which each new EGU requests allowances shall be calculated using the following formula*:*

$$Allocation = \frac{1.0 lb\ NOx}{MWh}\ X\ \frac{Size\ of\ unit\ in\ MW\ x\ hours\ of\ operation}{2000\ lb / ton}\ X\ 70\%$$

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on gross electric generation.
Size of the unit =	The nameplate capacity, as defined in the CAIR NOx program of the EGU in megawatts.
Hours of Operation =	Predicted hours of operation per control period.
MWh =	Megawatt hours.

(c) The allocation methodology used for each consecutive ozone season for which each new EGU requests allowances shall be calculated using the following formula*:*

$$Allocation = \frac{1.0 lb\ NOx}{MWh}\ X\ \frac{Actual\ Megawatt\ hours}{2000\ lb / ton}$$

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on gross electric generation.
Actual megawatt hours =	The actual megawatt hours of electricity generated during the control period immediately preceding the request.
MWh =	Megawatt hours.

(d) When the new EGU has been placed in the existing pool, the calculation methods under R 336.1822 apply.

(5) The department shall review and allocate oxides of nitrogen allowances pursuant to each allocation request on a pro rata basis as follows:

(a) Upon receipt of the CAIR NOx unit's allowance allocation request, the department shall determine whether allowances are available and shall make necessary adjustments to the request to ensure that for the CAIR NOx ozone season control period, the number of allowances specified are consistent with the requirements of subrule (1) of this rule.

(b) If the allocation set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount greater than or equal to the number requested, as adjusted under subdivision (a) of this subrule, then the department shall allocate the amount of the CAIR NOx ozone season allowances requested.

(c) If the allocation set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, as adjusted under subdivision (a) of this subrule, then the department shall proportionately reduce the number of CAIR NOx ozone season allowances allocated to each CAIR NOx ozone season unit so that the total number of CAIR NOx ozone season allowances allocated are equal to the amounts referenced in subrule (1)(a), (b) or (c) of this rule.

(6) CAIR NOx ozone season allowances not allocated or requested that remain in the new source set-aside pool for any allocation year shall be re-allocated to the existing EGU and non-EGU source pools, using the allocation methodologies as outlined in R 336.1822 and based on a ratio of the number of allowances remaining in the pool and the number of allowances in the EGU's and non-EGU's budget.

(7) Not later than July 31 of the year for which the allowances are allocated, the department shall submit to the U.S. environmental protection agency the CAIR NOx ozone season allowance allocations, as determined under this rule.

R 336.1824 CAIR NOx ozone season trading program; hardship set-aside.

Rule 824. (1) After the provisions of R 336.1822 have been followed, the authorized account representative may pursue a request for hardship allowances. These requests must be submitted not later than 30 days prior to the deadline for department submittals to the U.S. environmental protection agency as described in R 336.1822.

(2) For existing EGUs and non-EGUs subject to the CAIR NOx ozone season budget, the department shall allocate CAIR NOx hardship allowances under the following procedures:

(a) The department shall establish a hardship allocation set-aside pool for each CAIR NOx ozone season allocation year starting in 2010. This hardship set-aside pool shall be allocated on an ozone season basis and contains a total of 650 tons per allocation year of CAIR NOx ozone season allowances, for any qualifying EGUs or non-EGUs.

(b) Hardship allowances may be allocated to an EGU or non-EGU, if the requesting authorized account representative demonstrates both of the following:

(i) The owner or operator of the EGU or a non-EGU has less than 250 employees within its company or its electric generating division or department.

(ii) The controls required for the EGU or non-EGU under this part result in excessive or prohibitive costs for compliance, pursuant to the procedures in subrule (3) of this rule.

(c) The CAIR authorized account representative of a CAIR NOx ozone season unit under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx ozone season hardship allowances. The authorized account representative shall submit the request for the amount of estimated hardship allowances they need, using historical ozone season heat input utilization levels multiplied by historical oxides of nitrogen emission rates as follows:

(i) Historical heat input utilization levels shall be based on the unit's average of the 2 highest heat input utilization levels for the ozone season in the 5 years immediately preceding the year in which the department is required to submit the oxides of nitrogen allocations to the U.S. environmental protection agency. If the unit operated less than 2 full ozone seasons during the 5-year time period, then the unit's single highest ozone season heat input level shall be used.

(ii) Historic oxides of nitrogen rates shall be based on the oxides of nitrogen rate reported by the authorized account representative in its 40 C.F.R. part 75 reports to the U.S. environmental protection agency in the calendar year immediately preceding the year in which the department is required to submit the oxides of nitrogen allocation.

(iii) Units receiving hardship allowances shall receive a 3-year allocation that is 3 years in advance of the 2010 ozone season. The 3-year allocation shall be the same as provided in R 336.1822(3).

(d) The department shall allocate the allowances from the hardship set-aside pool based on the requests received as follows:

(i) If the allocation hardship set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount of oxides of nitrogen allowances greater than or equal to the number requested, then the department shall allocate the amount of the CAIR NOx ozone season allowances requested.

(ii) If the allocation hardship set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, then the department shall proportionately reduce the number of CAIR NOx ozone season allowances allocated to each CAIR NOx ozone season unit so that the total number of CAIR NOx ozone season allowances allocated are equal to the amounts in R 336.1822(1)(a)(v) or (b)(v).

(3) The department shall allocate CAIR NOx ozone season hardship allowances to existing EGUs and existing non-EGUs which have submitted an engineering analysis as described in the following procedures:

(a) The authorized account representative shall demonstrate to the department that the control level required pursuant to this rule results in excessive or prohibitive cost for compliance. The demonstration shall include all of the following:

(i) An engineering study analyzing all control options that are technically available for the unit, including control options that would achieve a level of control meeting, at a minimum, the levels as specified in subparagraphs (A), (B), and (C) of this paragraph. Sources that previously submitted an engineering analysis and received hardship allowances pursuant to R 336.1810(4)(f) for the oxides of nitrogen budget program may submit written updates to their previous plan.

(A) A NOx emission rate of 0.15 pound per million Btu for EGUs during the 2010 through 2014 time period.

(B) A NOx emission rate of 0.125 pound per million Btu for EGUs from 2015 and beyond.

(C) A NOx emission rate of 0.17 pound per million Btu for non-EGUs.

(ii) The annualized cost associated with each control option. An annualized cost of more than $2,400 per ton of oxide of nitrogen reduced shall generally be considered to be an excessive cost for compliance with this rule.

(iii) Other considerations that contribute to prohibitive cost of compliance.

(b) For a source to remain eligible for hardship allowances under this rule after the initial 3-year allocation period, ending on September 30, 2011, the state may require a revised engineering analysis and demonstration as referenced in subrule (3)(a) of this rule, at a minimum of once every 3 years.

R 336.1825 CAIR NOx ozone season trading program; renewable set-aside.

Rule 825. (1) The department shall establish a renewable allocation set-aside pool for each CAIR NOx ozone season control period for applicable units starting in 2010. This renewable set-aside pool shall be allocated on a yearly basis and contain a total of 200 tons of oxides of nitrogen allowances per allocation year.

(2) An authorized account representative of a renewable energy source or renewable energy project, as defined under R 336.1803(3), may request a CAIR NOx ozone season allowance allocation under this rule.

(3) Once an authorized account representative of a renewable energy source or renewable energy project has requested allowances from the CAIR NOx ozone season budget, the department shall allocate CAIR NOx ozone season renewable allowances under the following procedures:

(a) The oxides of nitrogen allowance allocation request shall be submitted before March 1 of the year of the first ozone control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the unit, if required, and each following year by March 1.

(b) The allocation methodology used for the first ozone season for which each renewable energy source or renewable energy project requests allowances shall be calculated using the following formula:

$$Allocation = \frac{1.0 lb\ NOx}{MWh}\ X\ \frac{Size\ of\ unit\ in\ MW\ x\ hours\ of\ operation}{2000\ lb / ton}\ X\ 70\%$$

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on gross electric generation.

Size of the unit =	The nameplate capacity, as defined in the CAIR NOx program, of the renewable energy source or renewable energy project in megawatts.
Hours of Operation =	Predicted hours of operation per control period.
MWh =	Megawatt hours.

(c) The allocation methodology used for the each consecutive ozone season for which the renewable energy source or renewable energy project requests allowances shall be calculated using the following formula:

$$Allocation = \frac{1.0 lb\ NOx}{MWh}\ X\ \frac{Actual\ Megawatt\ hours}{2000\ lb\ /\ ton}$$

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on electric generation.
Actual megawatt hours =	The actual megawatt hours of electricity generated during the control period immediately preceding the request.
MWh =	Megawatt hours.

(4) The renewable energy source or renewable energy project's eligibility for allowances shall begin not sooner than the calendar year 2005.

(5) An individual renewable energy source alone or as part of a renewable energy project may only receive allowances for 3 consecutive ozone seasons.

(6) CAIR NOx ozone season allowances not allocated or requested that remain in the renewable allocation set-aside pool for any allocation year shall be re-allocated to the existing EGU and non-EGU source pools, using the allocation methodologies as outlined in Rule 822 and based on a ratio of the number of allowances remaining in the pool and the number of allowances in the EGU's and non-EGU's budget.

(7) If the renewable allocation set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, then the department shall proportionately reduce the number of CAIR NOx ozone season allowances allocated to each CAIR NOx ozone season unit requesting such allowances, so that the total number of CAIR NOx ozone season allowances allocated are equal to the amounts in R 336.1822(1)(a)(iv) or (b)(iv).

R 336.1826 CAIR NOx ozone season trading program; opt-in provisions.

Rule 826. The opt-in provisions in 40 C.F.R. §§97.380 to 97.388 are adopted by reference in R 336.1802a and are applicable to this rule.

R 336.1830 CAIR NOx annual trading program; allowance allocations.

Rule 830. (1) The CAIR NOx annual trading program budget allocated by the department for the CAIR NOx annual control periods shall annually equal the total number of tons of oxides of nitrogen emissions as follows and apportioned to the

CAIR NOx EGUs, as determined by the procedures in this rule. These allocations shall be distributed in the following manner:

(a) The total CAIR NOx annual budget for the annual control periods of 2009 to 2014 is 65,304 tons. These allocations shall be distributed in the following manner:

(i) The CAIR NOx annual budget available to existing EGUs as follows:

(A) For the 2009 through 2011 annual control periods is 63,104.

(B) For the 2012 through 2014 annual control periods is 62,704.

(ii) The CAIR NOx annual budget available to new EGUs as follows:

(A) For the 2009 through 2011 annual control periods is 1,000 tons.

(B) For the 2012 through 2014 annual control periods is 1,400 tons.

(iii) The CAIR NOx annual budget available to all existing EGUs that have submitted an acceptable demonstration of a hardship to the department, in the 2009 to 2014 annual control periods is 1,200 tons.

(b) The total CAIR NOx annual budget for the annual control periods of 2015 and thereafter is 54,420 tons. These allocations shall be distributed as follows:

(i) The CAIR NOx annual budget available for existing EGUs in the 2015 and thereafter annual control periods is 51,820 tons.

(ii) The CAIR NOx annual budget available for new EGUs in the 2015 and thereafter annual control periods is 1,400 tons.

(iii) The CAIR NOx annual budget available to all existing EGUs that have submitted an acceptable demonstration of a hardship to the department, in the 2015 and thereafter annual control periods is 1,200 tons.

(2) The department shall allocate CAIR NOx annual budget allowances to existing EGUs. A 3-year allocation is 2 and 3 years in advance of the 2009 and 2010 annual control period, respectively, and 4 years in advance of each subsequent annual control period. The 3-year allocation shall be as follows:

(a) By 60 days after the effective date of this rule or April 30, 2007, whichever is earlier, the department shall submit to the U.S. environmental protection agency the CAIR NOx annual allowance allocations, under subrule (3) of this rule, for the annual control periods in 2009, 2010, and 2011.

(b) By October 31, 2008, the department shall submit to the U.S. environmental protection agency the CAIR NOx annual allowance allocations, under subrule (3) of this rule, for the annual control periods in 2012, 2013, and 2014.

(c) By October 31, 2011, and thereafter each October 31 of the year that is 3 years after the last year of allocation submittal, the department shall submit to the U.S. environmental protection agency the CAIR NOx annual allowance allocations as indicated under subrule (3) of this rule.

(3) For the CAIR NOx annual control periods under subrules (1)(a) and (b) of this rule, the department shall allocate allowances to existing EGU units that commenced operation before January 1 of the most recent year of the 5-year period used to calculate heat input. The department shall allocate the following allowances to each existing EGU:

(a) During calendar years 2009 to 2014:

(i) Units with an allowable NOx emission rate equal to or greater than the CAIR target budget rate of 0.15 pounds per million Btu shall receive an initial unadjusted allocation of allowances in an amount equaling 0.15 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(ii) Units with an allowable emission rate less than the CAIR target budget rate of 0.15 pounds per million Btu shall receive allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

$$Allocation = \left[\frac{\left\{ \frac{(CTER \ X \ FAF) + AER}{2} \right\} X \ HI}{2000 \ lb / ton} \right]$$

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2009 through 2014.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate of 0.15 pounds per mm Btu.
HI =	Average of the unit's 2 highest heat inputs in mm Btu for the appropriate 5 control periods.

(b) During calendar years 2015 and thereafter, the following apply:

(i) Units with an allowable NOx emission rate equal to or greater than the CAIR target budget rate of 0.125 pounds per million Btu shall receive an initial unadjusted allocation of allowances in an amount equaling 0.125 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(ii) Units with an allowable emission rate less than the CAIR target budget rate of 0.125 pounds per million Btu shall receive allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

$$Allocation = \left[\frac{\left\{ \frac{(CTER \ X \ FAF) + AER}{2} \right\} X \ HI}{2000 \ lb / ton} \right]$$

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2015 and thereafter.
FAF =	Fuel adjustment factor as defined in R 336.1821.

AER = The unit's allowable emission rate of 0.125 pounds per mm Btu.
HI = Average of the unit's 2 highest heat inputs in mm Btu for the appropriate 5 control periods.

(4) The heat input, in million Btu's, used for calculating oxides of nitrogen allowance allocations for each subject unit under this rule shall be the unit's average of the 2 highest heat inputs for the annual control period in the 5 years immediately preceding the year in which the department is required to submit the oxide of nitrogen allocations. If the unit operated less than 2 years of the 5-year time period, then the unit's single highest heat input shall be used.

(5) If the initial total number of CAIR NOx annual budget allowances allocated to all existing EGUs for the years under subrule (3) of this rule does not equal the budgeted tons for such units as specified in subrule (1) of this rule, then the department shall adjust up or down the total number of CAIR NOx annual budget allowances allocated to each existing EGU so that the total number of CAIR NOx annual budget allowances allocated to the entire group of EGUs equals the appropriate value in subrule (1) of this rule. The adjustment shall be made by multiplying each unit's unadjusted initial allocation by a correction factor determined by dividing the appropriate existing EGU total annual budget tons from subrule (1) of this rule by the sum of all existing EGU's initial unadjusted allocations, and rounding to the nearest whole ton, as appropriate.

R 336.1831 New EGUs under CAIR NOx annual trading program; allowance allocations.

Rule 831. (1) The department shall establish a set-aside pool for each CAIR NOx annual control allocation year. This set-aside pool shall be allocated on a yearly basis as follows:

(a) For years 2009 to 2011, a total of 1,000 tons of CAIR NOx annual budget allowances available for new EGUs.

(b) For years 2012 and thereafter, a total of 1,400 tons of CAIR NOx annual budget allowances available for new EGUs.

(2) The CAIR authorized account representative of a new EGU under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx annual allowances, starting with the annual control period during which the EGU commenced or is projected to commence operation and ending with the control period preceding the control period for which it shall receive an allocation under R 336.1830.

(a) The oxides of nitrogen allowance allocation request shall be submitted before September 1 of the year of the first annual control period for which the allowance allocation is requested and after the date on which the department issues a permit to install for the new EGU, if required, and each following year by September 1.

(b) The allocation methodology used for the first annual control period for which each new EGU requests allowances shall be calculated using the following formula*:*

$$Allocation = \frac{1.0 lb\ NOx}{MWh}\ X\ \frac{Size\ of\ unit\ in\ MW\ x\ hours\ of\ operation}{2000\ lb\ /\ ton}\ X\ 70\%$$

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on gross electric generation.
Size of the unit =	The nameplate capacity, as defined in the CAIR NOx program, of the EGU in megawatts.
Hours of operation =	Predicted hours of operation per control period.
MWh =	Megawatt hours.

(c) The allocation methodology used for each consecutive annual control period for which each new EGU requests allowances shall be calculated using the following formula*:*

$$Allocation = \frac{1.0 lb\ NOx}{MWh}\ X\ \frac{Actual\ Megawatt\ hours}{2000\ lb\ /\ ton}$$

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on gross electric generation.
Actual megawatt hours =	The actual megawatt hours of electricity generated during the control period immediately preceding the request.
MWh =	Megawatt hours.

(d) Once the new EGU has been placed in the existing pool, the calculation methods under R 336.1830 apply.

(3) The department shall review and allocate oxides of nitrogen allowances pursuant to each allocation request on a pro rata basis as follows:

(a) Upon receipt of the CAIR NOx unit’s allowance allocation request, the department shall determine whether allowances are available and shall make necessary adjustments to the request to ensure that for the CAIR NOx annual control period, the numbers of allowances specified are consistent with the requirements of subrule (1) of this rule.

(b) If the allocation set-aside pool for the CAIR NOx annual control period for which CAIR NOx annual budget allowances are requested has an amount greater than or equal to the number requested, as adjusted under subdivision (a) of this subrule, then the department shall allocate the amount of the CAIR NOx annual budget allowances requested.

(c) If the allocation set-aside pool for the CAIR NOx annual control period for which CAIR NOx annual budget allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, as adjusted under subdivision (a) of this subrule, then the department shall proportionately reduce the number of CAIR NOx annual budget allowances allocated to each CAIR NOx unit so that the total number of CAIR NOx annual budget allowances allocated are equal to the amounts referenced in subrule (1)(a) or (b) of this rule.

(4) CAIR NOx annual allowances not allocated or requested that remain in the new source set-aside pool for any allocation year shall be re-allocated to the existing EGU source pool, using the allocation methodologies as outlined in R 336.1830.

R 336.1832 CAIR NOx annual trading program; hardship set-aside.

Rule 832. (1) After the provisions of R 336.1830 have been followed, an owner or operator may pursue a request for hardship allowances. These requests must be submitted not later than 30 days prior to the deadline for department submittals to the U.S. environmental protection agency as described in R 336.1830.

(2) For existing EGUs subject to the CAIR NOx annual budget, the department shall allocate CAIR NOx hardship allowances under the following procedures:

(a) The department shall establish a hardship allocation set-aside pool for each CAIR NOx annual allocation year for existing EGUs. This hardship set-aside pool shall be allocated on a yearly basis and contains 1,200 tons of CAIR NOx annual allowances per allocation year.

(b) Hardship allowances may be allocated to an EGU if the requesting authorized account representative demonstrates both of the following:

(i) The owner or operator of the EGU has less than 250 employees within its company or its electric generating division or department.

(ii) The controls required for the EGU under this part result in excessive or prohibitive costs for compliance, pursuant to the procedures in subrule (3) of this rule.

(c) The CAIR authorized account representative of a CAIR NOx unit under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx annual hardship allowances. The authorized account representative shall submit the request for the amount of estimated hardship allowances they need, using historical annual heat input utilization levels multiplied by historical oxides of nitrogen emission rates, in the following manner:

(i) Historical heat input utilization levels shall be based on the unit's average of the 2 highest heat input utilization levels for the annual control period in the 5 years immediately preceding the year in which the department is required to submit the oxides of nitrogen allocations to the U.S. environmental protection agency. If the unit operated less than 2 years during the 5-year time period, then the unit's single highest heat input level shall be used.

(ii) Historic oxides of nitrogen rates shall be based on the oxides of nitrogen rate reported by the authorized account representative in its 40 C.F.R. part 75 reports to the U.S. environmental protection agency in the calendar year immediately preceding the year in which the department is required to submit the oxides of nitrogen allocation.

(iii) Units receiving hardship allowances shall receive a 3-year allocation that is 2 and 3 years in advance of the 2009 and 2010 annual control periods, respectively, and 4 years in advance of each subsequent annual control period. The 3-year allocation shall be the same as provided in R 336.1830(2).

(d) The department shall allocate the allowances based on the requests received as follows:

(i) If the allocation hardship set-aside pool for the CAIR NOx annual control period for which CAIR NOx annual allowances are requested has an amount of oxides of nitrogen allowances greater than or equal to the number requested, then the department shall allocate the amount of the CAIR NOx annual budget allowances requested.

(ii) If the allocation hardship set-aside pool for the CAIR NOx annual control period for which CAIR NOx annual allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, then the department shall proportionately reduce the number of CAIR NOx annual allowances allocated to each CAIR NOx annual unit so that the total number of CAIR NOx annual allowances allocated are equal to the amounts referenced in subdivision (a) of this subrule.

(3) The department shall allocate CAIR NOx annual hardship allowances to existing EGUs which have submitted an engineering analysis as described as follows:

(a) The authorized account representative shall demonstrate to the department that the control level required pursuant to this rule results in excessive or prohibitive cost for compliance. The demonstration shall include all of the following:

(i) An engineering study analyzing all control options that are technically available for the unit, including control options that would achieve a level of control meeting, at a minimum, a 0.15 pound per million Btu emission rate.

(ii) The annualized cost associated with each control option. An annualized cost of more than $2,400 per ton of oxides of nitrogen reduced shall generally be considered to be an excessive cost for compliance with this rule.

(iii) Other considerations that contribute to prohibitive cost of compliance.

(b) For a source to remain eligible for hardship allowances under this rule after the initial 3-year allocation period, ending on December 31, 2011, the state may require a revised engineering analysis and demonstration as detailed under subrule (3)(a) of this rule, at a minimum of once every 3 years.

R 336.1833 CAIR NOx annual trading program; compliance supplement pool.

Rule 833. (1) The department shall allow sources required to implement CAIR NOx control measures by January 1, 2009, and subject to this rule to demonstrate compliance using allowances issued from the compliance supplement pool under this rule, as follows:

(a) The total number of CAIR NOx allowances available to existing EGUs, for early reduction purposes from the compliance supplement pool, shall not be more than 6,491 tons of oxides of nitrogen.

(b) The total number of CAIR NOx allowances available for the newly-affected EGUs, for hardship purposes from the compliance supplement pool, shall not be more than 1,856 tons of oxides of nitrogen.

(c) Any CAIR NOx allowances that remain in the compliance supplement pool after the 2009 control period shall be retired.

(d) Sources that receive allowances according to the requirements of this rule may trade the allowance to other sources or persons according to the provisions in the CAIR NOx annual trading program.

(2) The department shall issue early reduction allowances to existing EGUs as follows:

(a) The emissions reduction shall not be required by Michigan's state implementation plan, state law, or rule, or be otherwise required by federal law.

(b) The emissions reduction shall be verified by the source as actually having occurred during the calendar years of 2007 and 2008.

(c) Each CAIR NOx unit for which the owner or operator requests any early reduction allowances under this rule shall monitor oxides of nitrogen emissions under 40 C.F.R. part 75, subpart H, which are adopted by reference in R 336.1802a, starting not less than 1 calendar year before the annual control period for which the early reduction allowances are requested. The unit's monitoring system availability shall be not less than 90 percent during the control period in which monitoring occurs for this purpose and the unit shall be in compliance with any applicable state or federal emissions or emissions-related requirements.

(d) The emissions reduction shall be quantified according to procedures set forth in 40 C.F.R. part 75, subpart H.

(e) The emissions reduction request shall include both of the following:

(i) The CAIR NOx authorized account representative may request early reduction allowances for the annual control period in an amount equal to the unit's heat input for the year, multiplied by the difference between the rates in both of the following provisions, divided by 2,000 pounds per ton, and rounded to the nearest ton:

(A) The oxides of nitrogen emission limit required by Michigan's state implementation plan, otherwise required by the clean air act, or 0.25 pound per million Btu heat input, whichever is most stringent.

(B) The unit's actual oxides of nitrogen emission rate for the 2007 and 2008 calendar years, which shall be lower than the rate used in subparagraph (A) of this paragraph and less than 80% of the actual 2005 annual oxides of nitrogen emission rate, expressed as pound per million Btu heat input.

(ii) The early reduction allowance request shall be submitted in writing, in a format specified by the department, not later than July 1, 2009, for the 2007 and 2008 control periods.

(f) The department shall allocate CAIR NOx allowances to CAIR NOx units meeting the requirements of this subdivision and requesting early reduction allocations, in the following manner:

(i) Upon receipt of each early reduction allowance request, the department shall accept the request only if the requirements of subdivisions (a) to (e) of this subrule are met and, if the request is accepted, shall make any necessary adjustments to the request to ensure that the amount of the early reduction allowances requested meets the requirement of subdivisions (a) to (e) of this subrule.

(ii) If the compliance supplement pool has an amount of CAIR NOx allowances equal to or greater than the number of early reduction allowances in all accepted early reduction allowance requests for 2007 and 2008, as adjusted under paragraph (i) of this subdivision, the department shall allocate to each CAIR NOx unit covered by the accepted requests 1 allowance for each early reduction allowance requested, as adjusted under paragraph (i) of this subdivision.

(iii) If the compliance supplement pool has an amount of CAIR NOx allowances less than the number of early reduction allowances in all accepted early reduction allowance requests for 2007 and 2008, as adjusted under paragraph (i) of this subdivision, the department shall allocate CAIR NOx allowances to each CAIR NOx unit covered by the accepted requests according to the following formula and rounding to the nearest whole allowance as appropriate:

$$Allocated\ ERC = \left(\frac{Units\ ERC\ requested}{Total\ requested\ ERC}\right) x\ Available\ CAIR\ NOx\ Allowances$$

Where:

ERC =	Early reduction allowances.
Allocated ERCs =	Each unit's allocated early reduction allowances.
Total requested ERCs =	The total amount of ERCs requested by all units from the compliance supplement pool.
Available CAIR NOx Allowances =	The total amount of allowances available from the early reduction portion of the compliance supplement pool.

(3) The department shall issue hardship allowances to newly-affected EGUs for which compliance with the CAIR NOx emissions limitations would create an undue risk to the reliability of electricity supply during the 2009 control period. The CAIR NOx authorized account representative of the newly-affected EGU may request the allocation of CAIR NOx allowances from the compliance supplement pool under subrule (1)(b) of this rule, pursuant to the following:

(a) The CAIR NOx authorized account representative shall submit to the department by July 1, 2009, a written request, in a format specified by the department, for allocation of an amount of CAIR NOx allowances from the compliance supplement pool not exceeding the minimum amount of CAIR NOx allowances necessary to remove the undue risk to the reliability of electricity supply.

(b) The CAIR NOx authorized account representative shall demonstrate that, in the absence of allocation of the amount of CAIR NOx allowances requested, the unit's compliance with the CAIR NOx emissions limitation for the 2009 control period would create an undue risk to the reliability of electricity supply during the 2009 control period. This demonstration shall include both of the following:

(i) A showing that it would not be possible for the owners and operators of the unit to obtain sufficient amounts of electricity from other electric generation facilities during the installation of control technology at the unit for compliance with the CAIR NOx emission limitation to prevent such undue risk.

(ii) A showing that it would not be possible for the owners and operators of the unit to obtain sufficient amounts of allowances under subrule (2) or from other sources or persons to prevent such undue risk.

(c) The department shall review each request submitted by July 1, 2009, and allocate CAIR NOx allowances for the 2009 control period to requesting units as follows:

(i) Upon receipt of each hardship request, the department shall accept the request only if the requirements of subdivisions (a) and (b) of this subrule are met and, if the request is accepted, shall make any necessary adjustments to the request to ensure that the amount of the CAIR NOx hardship allowances requested meets the requirements of subdivisions (a) and (b) of this subrule.

(ii) If the compliance supplement pool has an amount of CAIR NOx hardship allowances equal to or greater than the number of CAIR NOx allowances in the hardship requests, the department shall allocate to each CAIR NOx unit the amount of CAIR NOx allowances requested, as adjusted under paragraph (i) of this subdivision.

(iii) If the compliance supplement pool has an amount of CAIR NOx allowances less than the number of hardship allowances in all accepted hardship requests, as adjusted under paragraph (i) of this subdivision, the department shall allocate CAIR NOx allowances to each CAIR NOx unit covered by the accepted requests according to the following formula and rounding to the nearest whole allowance as appropriate:

$$Adjusted\ Allocation = \mathrm{Re}quested\ Allocation\ \ X \left(\frac{Available\ Pool\ Allocations}{Total\ adjusted\ allocation\ for\ all\ units} \right)$$

Where:

Adjusted allocation =	The number of CAIR NOx hardship allowances allocated to the unit from the state's compliance supplement pool.
Requested allocation =	The amount of CAIR NOx hardship allowances requested for the unit.
Available pool allocations =	The amount of CAIR NOx hardship allowances in the state's compliance supplement pool.
Total adjusted allocations for all units =	The sum of the amounts of hardship allocations requested for all units, as adjusted.

(4) The department shall complete its review process not later than September 1, 2009. By November 30, 2009, the department shall determine, and submit to the U.S. environmental protection agency, the allocations under subrules (2) or (3) of this rule.

R 336.1834 Opt-in provisions under the CAIR NOx annual trading program.

Rule 834. The opt-in provisions in 40 C.F.R. §§97.180 through 97.188 are adopted by reference in R 336.1802a and are applicable to this rule.

ATTACHMENT B

STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENTAL QUALITY
LANSING

JENNIFER M. GRANHOLM
GOVERNOR

DEQ

STEVEN E. CHESTER
DIRECTOR

May 25, 2007

RECEIVED
MAY 29 2007
AIR QUALITY DIV.

Ms. Norene Lind, Administrative Rules Manager
State Office of Administrative Hearings and Rules
Department of Labor and Economic Growth
Ottawa Building - Fourth Floor
611 West Ottawa
Lansing, Michigan 48933-1070

Dear Ms. Lind:

SUBJECT: Certificate of Adoption for Administrative Rules Promulgated Pursuant to Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as Amended (Act 451), SOAHR 2005-037EQ

The Certificate of Adoption for the administrative rules promulgated pursuant to Part 55 of Act 451 is being forwarded to you, along with a reference copy of the administrative rules, in accordance with the provisions of Executive Order 2005-1 and the January 5, 1996, memorandum from the former Office of Regulatory Reform. These rules are being developed to meet requirements of the U.S. Environmental Protection Agency's Clean Air Interstate Rule to reduce transported emissions of oxides of nitrogen from electric generating units and large non-electric generating units.

The rules were certified by the Legislative Service Bureau on May 15, 2007, and were formally approved by your office on May 16, 2007. The rules were delivered to the Joint Committee on Administrative Rules on May 16, 2007.

If you have questions or comments regarding the rule changes, please contact Ms. Susan Maul, Acting Regulatory Reform Officer, at 517-241-1552, or you may contact me.

Sincerely,

Steven E. Chester
Director
517-373-7917

Enclosures

cc: Mr. Jim Sygo, Deputy Director, DEQ
Ms. Susan Maul, Acting Regulatory Reform Officer, DEQ
Mr. G. Vinson Hellwig, DEQ
Ms. Mary Ann Halbeisen, DEQ
Ms. Teresa Walker, DEQ
cc/enc: AQD, SOAHR 2005-037EQ File

STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENTAL QUALITY
LANSING

JENNIFER M. GRANHOLM
GOVERNOR

STEVEN E. CHESTER
DIRECTOR

CERTIFICATE OF ADOPTION

I, Steven E. Chester, Director of the Department of Environmental Quality, do formally adopt the attached administrative rules by amending R 336.1803 and by adding R 336.1802a, R 336.1821, R 336.1822, R 336.1823, R 336.1824, R 336.1825, R 336.1826, R 336.1830, R 336.1831, R 336.1832, R 336.1833 and R 336.1834 of the Michigan Administrative Code.

These rules are adopted pursuant to Sections 5503 and 5512 of Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended, and Executive Order 1995-18.

5-24-07
Date

Steven E. Chester, Director

SOAHR 2005-037EQ

ATTACHMENT C

STATE OF MICHIGAN
OFFICE OF THE GOVERNOR

JENNIFER M. GRANHOLM
~~JOHN ENGLER~~
GOVERNOR

February 22, 2003

Mr. Thomas V. Skinner, Regional Administrator
U.S. Environmental Protection Agency
Region 5
77 West Jackson Boulevard (R-19J)
Chicago, Illinois 60604-3507

Dear Mr. Skinner:

The federal Clean Air Act (CAA) requires Michigan to submit revisions to the State Implementation Plan. It also provides an opportunity for the state to request delegations and make grant applications to fund air quality programs.

I hereby delegate my authority to make any submittal, request, or application under the CAA to Director Steven E. Chester of the Michigan Department of Environmental Quality (MDEQ). This delegation was effective on January 1, 2003.

Sincerely,

Jennifer M. Granholm
Governor

cc: Mr. Steven E. Chester, Director, MDEQ
Mr. Stanley F. Pruss, Deputy Director, MDEQ

ATTACHMENT D

LEGISLATIVE
SERVICE
BUREAU
Since 1941

THIS COPY TO BE FILED
WITH
SECRETARY OF STATE

Legal Division
John C. Bollman, Director

CERTIFICATE OF APPROVAL

I hereby certify that the Legislative Service Bureau has examined the attached proposed rules of the Department of Environmental Quality, dated April 17, 2007, amending R 336.1803, and adding R 336.1802a, R 336.1821, R 336.1822, R 336.1823, R 336.1824, R 336.1825, R 336.1826, R 336.1830, R 336.1831, R 336.1832, R 336.1833 and R 336.1834 to the Department's rules entitled "Air Pollution Control, Part 8. Emission Limitations and Prohibitions-Oxides of Nitrogen," and further certify that, pursuant to section 45 of 1969 PA 306, MCL 24.245, the Legislative Service Bureau approves the rules as to form, classification, and arrangement.

Dated: May 15, 2007

LEGISLATIVE SERVICE BUREAU

By Elliott Smith / M. Martin
Elliott Smith, Director

Michigan Legislature
124 W. Allegan Street, 3rd Floor • P.O. Box 30036 • Lansing, MI 48909-7536 • (517) 373-9425 • Fax: (517) 373-5642

JENNIFER M. GRANHOLM
GOVERNOR

STATE OF MICHIGAN
STATE OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
LANSING

PETER L. PLUMMER
EXECUTIVE DIRECTOR

May 16, 2007

Ms. Colleen Curtis
Joint Committee on Administrative Rules
Boji Tower; 4th Floor - 124 W. Allegan
P.O. 30036
Lansing, Michigan 48909-7536

Dear Ms. Curtis:

On behalf of the State Office of Administrative Hearings and Rules, I hereby submit the following rule set for consideration by the Joint Committee on Administrative Rules:

(2005-037 EQ) **Air Pollution Control - Part 8. Emission Limitations and Prohibitions Oxides of Nitrogen**

Enclosed, you will find copies of the following:

1. 1 copy of the LSB formal certificate.
2. 1 copy of the SOAHR formal certificate.
3. 1 copy of the Regulatory Impact Statement.
4. 1 copy of the draft rules.
5. 1 copy of the JCAR Agency Report.

Please let me know if you have any questions. I can be reached at 1-4146.

Thanks.

Sincerely,

Norene Lind, Administrative Rules Manager
State Office of Administrative Hearings and Rules

enclosures

STATE OF MICHIGAN

JENNIFER M. GRANHOLM
GOVERNOR

STATE OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

PETER L. PLUMMER
EXECUTIVE DIRECTOR

LEGAL CERTIFICATION OF RULES

I certify that I have examined the attached administrative rules, dated April 17, 2007, in which the Department of Environmental Quality proposes to modify a portion of the Michigan Administrative Code entitled, "**Air Pollution Control – Part 8. Emission Limitations and Prohibitions – Oxides of Nitrogen,**" by:

- Amending R 336.1803.
- Adding R 336.1802a, R 336.1821, R 336.1822, R 336.1823, R 336.1824, R 336.1825, R 336.1826, R 336.1830, R 336.1831, R 336.1832, R 336.1833 and R 336.1834.

The Legislative Service Bureau has approved the proposed rules as to form, classification, and arrangement.

I approve the rules as to legality pursuant to the Administrative Procedures Act, MCL 24.201 *et seq.* and Executive Order No. 2005-1. In certifying the rules as to legality, I have determined that they are within the scope of the authority of the agency, do not violate constitutional rights, and are in conformity with the requirements of the Administrative Procedures Act.

Dated: 5/16/07

State Office of Administrative Hearings and Rules

By: [signature]
Peter L. Plummer, Executive Director

2005-037 EQ

ATTACHMENT E

Agency Report to the
JOINT COMMITTEE ON ADMINISTRATIVE RULES

This form must be completed by the department/agency that has the statutory authority for promulgating the rules. Please send an electronic copy of this form to the State Office of Administrative Hearings and Rules (SOAHR) at **soahr_rules@michigan.gov**. The SOAHR will review the document, the newspaper advertisements, and the corresponding rules prior to completing the legal certification of the rules. Please be sure to send to the SOAHR proofs of publication for the three newspaper advertisements required by MCL 24.242(1). You may mail them or send them as a scanned attachment.

Department

Environmental Quality

Division/agency/bureau:

Air Quality Division

Rule set number (as assigned by SOAHR)

2005-037EQ

Title of rules:

Part 8, Emission Limitations and Prohibitions—Oxides of Nitrogen

1. Name, address, FAX and phone numbers of agency contact person:

Mary Ann Halbeisen, Constitution Hall; Phone 517-373-7045; Fax 517-241-7499

2. Purpose for the proposed rules and background:

These rules are being developed to meet requirements of the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR) to reduce transported emissions of oxides of nitrogen (NOx) from electric generating units (EGUs) and large non-electric generating units (non-EGUs). The rules will be submitted to the EPA as part of the Michigan State Implementation Plan (SIP) upon final promulgation.

The federal CAIR program requires the state to develop the regulations to reduce NOx emissions. The proposed rules will result in reduced NOx emissions from EGUs and large non-EGUs, which will help reduce the formation of particulate matter less than 2.5 microns in diameter and ground-level ozone in Michigan and downwind areas. The Department of Environmental Quality (DEQ) worked with a number of stakeholders to develop and adopt these rules. The workgroup included representatives from various industrial, commercial, small business, consumer and environmental groups and associations. The workgroup met several times during 2005 and 2006.

3. Summary of proposed rules:

Rules 802a, 803, 821 through 826, and 830 through 834 are based on the EPA CAIR rules, a NOx emissions cap and trade system to be administered by the EPA.

- Rule 802a contains adoption by reference language.
- Rule 803 modifies the existing definitions to address the CAIR requirements.
- Rule 821 contains applicability criteria.
- Rule 822 establishes the NOx budgets for the ozone season control period and establishes the allocation methodology procedures for the ozone season. See the attached spreadsheets for the allocation tables for each group.
- Rule 823 establishes the provisions for a new source set-aside ozone season control period allocation pool for new EGUs, new non-EGUs, and newly affected EGUs (which were not included in the original NOx program due to geographic location).
- Rule 824 establishes the provisions for a hardship set-aside ozone season control period allocation pool to address issues for small businesses that are impacted by the rules.
- Rule 825 establishes the provisions for a renewable set-aside ozone season control period allocation pool to encourage the use of renewable energy in the production of electricity in the state.
- Rule 826 adopts by reference the ozone season control period opt-in provisions under the federal CAIR rules.
- Rule 830 establishes the NOx budgets for the annual control period and establishes the allocation methodology procedures for the annual control period. See the attached spreadsheets for the allocation tables for each group.
- Rule 831 establishes the provisions for a new source set-aside annual control period allocation pool for new EGUs.
- Rule 832 establishes the provisions for a hardship set-aside annual control period allocation pool to address issues for small businesses that are impacted by the rules.
- Rule 833 establishes the provisions for an annual control period compliance supplement pool with early reduction credit generation and hardship provisions for the newly affected EGUs that were not in the original NOx Budget Program and are adversely impacted by this new program for 2009.
- Rule 834 adopts by reference the opt-in provisions for the annual control period under the federal CAIR rules.

4. Name of newspapers and date of publication in newspapers (minimum 3 newspapers of general circulation, representing different parts of the state, one of which must be located in the Upper Peninsula):

The notice was published in the following newspapers on February 23, 2007:
Lansing State Journal
Grand Rapids Press
Oakland Press
Marquette Mining Journal

5. Time, date, location and duration of public hearing:

April 2, 2007; 1:00-1:20 p.m.; Constitution Hall, 525 West Allegan Street, Lansing, Michigan.

6.* Date of publication of rules and public hearing notice in *Michigan Register:

March 1, 2007

7. Agency representative(s) attending hearing (include agency name and title of representative[s]):

The following attended from the Michigan Department of Environmental Quality, Air Quality Division:

Mary Ann Halbeisen, Administrative Rules Coordinator
Marion Hart, Supervisor, Administration Section
G. Vinson Hellwig, Division Chief
Robert Irvine, Supervisor, Strategy Development Unit
Randy Johnson, Administration Section
Mary Maupin, Environmental Quality Specialist, Strategy Development Unit
Teresa Walker, Environmental Quality Analyst, Strategy Development Unit

8. Names, organizations and (complete) addresses of persons attending the hearing:

- Susan Maul, Regulatory Affairs Officer, Department of Environmental Quality
- Lou Pocalujka, Sr. Environmental Planner, Consumers Energy, 1945 W. Parnall Road, Jackson, Michigan 49201
- Mike Weber, Director Environmental Affairs, CMS Enterprises, One Energy Plaza, Jackson, Michigan 49201

9. Persons submitting letters, comments and testimony of support:

- A.K. Evans, Director of Air Quality, Environmental & Laboratory Services Department, Consumers Energy, 1945 W. Parnall Road, Jackson, Michigan 49201
- Michael R. Weber, CMS Enterprises Co., One Energy Plaza, Jackson, Michigan 49201
- William Rogers, Senior Ethnological Specialist, Environmental Strategies, Detroit Edison Company, 2000 Second Avenue, Detroit, Michigan 48226
- Richard F. VanderVeen, President, Mackinaw Power, L.L.C., 414 E. Main Street, Suite B, Lowell, Michigan 49331
- David Gard, Energy Program Director, Michigan Environmental Council; Richard F. Vander Veen, President, Mackinaw Power; Debra Jacobson, Owner and Principal, DJ Consulting LLC; Alden Hathaway, Director, EcoPower Programs, Environmental Resources Trust; and Colin High, Chairman, Resource Systems Group

- Douglas Aburano, Environmental Engineer, U.S. Environmental Protection Agency, Region 5
- Kristine M. Krause, P.E., Vice President-Environmental, WE Energies, 231 W. Michigan Street, Milwaukee, Wisconsin, 53203

10. Persons submitting letters, comments and testimony of opposition:

None

11. Summary of suggestions to modify proposed rules:

The following comments received involve clerical and technical corrections to the rules. DEQ made the corrections and does not believe these changes are substantial or change the regulatory impact of the rules.
a. Michael Weber, Environmental Services, CMS Enterprises Co.
In general the company is supportive of the rules as proposed and offered several editorial or typographical corrections. These are as follows:
Comment: 803(3)(c)(i) -- "The highlighted references to Rule 803(3)(d) appear to be intended as a reference to a definition for "CAIR NOx ozone season unit." However, 803(3)(d) is the definition of "EGU," and the reference seems to be incorrect. There actually is no definition of "CAIR NOx ozone season unit" to be found in Rule 803. We note that Rule 821(1)(b) references the definition of "ozone season CAIR NOx unit" found in 40 CFR Part 97, and we suggest that the highlighted references above could be replaced with "40 CFR Part 97."
Response: DEQ agrees and has made the correction to clarify the rules
Comment: 803(3)(j)(iv) -- "New" two DIG combined-cycle gas turbine units meet the CAIR cogeneration unit definition, and would otherwise be exempt from CAIR, except for the fact that they were included in the original ozone season NOx budget trading program. Although they were included in that program as EGUs, EPA later provided guidance that cogeneration units should have been considered non-EGUs under that program. Under the definitions of "Michigan EGUs" at 803(3)(h) and the unmodified "Michigan non-EGUs" at 803(3)(j), these two DIG units would continue to be considered EGUs. We note that Rule 821(1)(b) correctly extends applicability of the CAIR ozone season program to these units, but it doesn't identify which budget (EGU or non-EGU) they fall under. The proposed language is intended to correctly identify where these units belong.
Response: DEQ has added the reference to clarify the applicability of these non-EGUs.
Comment: 821(4) -- Rules 822 and 830 both refer to use of "the appropriate fuel adjustment factor" in determining unit allocations; however, that term is never defined. The proposed language is intended to clarify what the "fuel adjustment factors" are.
Response: Parentheses are frowned on in the text of rules. DEQ has modified the statement to include the correction to clarify the rules and address the administrative policies.
Comment: 822(1) **--** The budget amounts described in the rest of this subrule could

perversely be interpreted as totals for the entire period of years described in each paragraph or subparagraph, instead of annual budget totals. The proposed language is intended to clarify the annual applicability of the budget amounts.
Response: DEQ does not interpret the wording in the same manner but has added the verbiage suggested as clarification to the rules.
Comment: 822(2) -- Rule 823 requires that newly-affected units apply for allowances from the new source set-aside pool. The proposed language is intended to clarify that the allowances are not just automatically granted.
Response: DEQ agrees and has added the clarifying terms.
Comment: 822(3)(a)(iii) **--** Subrules (3)(a)(i) and (ii) specify the ozone season control periods for which the DEQ shall submit allowance allocations. This language is intended to clarify that each subsequent submittal is for the next three control periods.
Response: DEQ needed to clarify the rule language for EPA and while it does not exactly match the source's suggestion it does address their concerns.
Comment: 822(4)(a)(i) **--** The reference to subrule (3) appears to be incorrect. The correct reference appears to be subrules (1)(a) and (b), as is stated in the comparable location of Rule 830. The "units with no applicable NOx emission rate" language in (4)(a)(i)(A) is intended to clarify coverage for any so-called "grandfathered" unit whose installation may have pre-dated any NOx emission limit. The "initial unadjusted allocation of" language is intended to clarify that the units will not necessarily receive the allowances calculated according to the formula (as written, the "units…shall receive allowances"). The initial allocation may later be adjusted in subrule (5). The changes in the table following the equation are intended to clarify what units the various terms are expressed in.
Response: DEQ agrees and added the language to clarify the rule's intent.
Comment: 822(4)(a)(ii) -- These changes are identical to those in 822(4)(a)(i), except for using the appropriate "2015 and thereafter" target emission rate.
Response: DEQ agrees and added the language to clarify the rule's intent.
Comment: 822(5) **--** As written, the total allocation to all EGUs and non-EGUs lumped together would be compared to the total budget for the two together, and would have been adjusted up or down together. This is inconsistent with keeping the two budgets and pools separate. Adjustments to allocations should be done to EGUs as a group separately from non-EGUs as a group. The proposed language is intended to accomplish that separation.
Response: DEQ agrees and added the language to clarify the rule's intent.
Comment: 823(3) **--** This subrule applies to new non-EGUs. The proposed language comes from the same requirement for new EGUs in Rule 823(4) and is needed for clarity.
Response: DEQ agrees and added the language to clarify the rule's intent.
Comment: 830(1) -- Same comment as for Rule 822(1)…The budget amounts described in the rest of this subrule could perversely be interpreted as totals for the entire period of years described in each paragraph or subparagraph, instead of annual budget totals. The proposed language is intended to clarify the annual applicability of the budget amounts.
Response: DEQ does not interpret the wording in the same manner but has added the

verbiage suggested as clarification to the rules.
Comment: 830(2)(c) -- Subrules (2)(a) and (b) specify the annual control periods for which the department shall submit allowance allocations. This language is intended to clarify that each subsequent submittal is for the next three annual control periods.
Response: In order to address CAMD's concerns, the wording has been modified to clarify the rule's intent. Although similar as suggested by the source, the change is not exact but addresses their concerns.
Comment: 830(3)(a) -- Same as for Rule 822(4)(a)(i)… The "units with no applicable NOx emission rate" language in (3)(a)(i) is intended to clarify coverage for any so-called "grandfathered" unit whose installation may have pre-dated any NOx emission limit. The "initial unadjusted allocation of" language is intended to clarify that the units will not necessarily receive the allowances calculated according to the formula (as written, the "units…shall receive allowances"). The initial allocation may later be modified in subrule (5). The changes in the table following the equation are intended to clarify what units the various terms are expressed in.
Response: DEQ agrees and added the language to clarify the rule's intent.
Comment: 830(3)(b) **--** These changes are identical to those in 830(3)(a), except for using the appropriate "2015 and thereafter" target emission rate.
Response: DEQ agrees and added the language to clarify the rule's intent.
Comment: 830(5) – CMS suggested adding a new subrule. Rule 830 is missing necessary language to adjust individual EGU allocations so that the sum over all EGUs equals the total budget amount.
Response: DEQ agrees and has added the additional language to clarify the process.
b. William Rogers, Senior Technological Specialist, Detroit Edison Company
In general the company is supportive of the rules as proposed and offered several editorial or typographical corrections. These are as follows:
Comment: 803(3)(g)(iii) -- Add coke oven gas to gaseous fuel definition.
Response: DEQ agrees and has made the change to clarify the rules.
Comment: 821(1)(c)(ii) -- Recommend changing renewable source projects to renewable energy projects to be consistent with definition in Rule 803(3)(o).
Response: DEQ agrees and the typo has been corrected.
Comment: Rule 822(4)(i)(A) identifies 0.15 pounds per million Btu as the CAIR target budget rate for 2009 through 2014. The formula in Rule 822(4)(a)(i)(B) identifies this same value as the CTER = Cair target emissions rate. This should be identically identified.
Response: Others have made similar comments. DEQ has made corrections to clarify the rule's intent.
Comment: Rule 822(4)(ii)(A) identifies 0.125 pounds per million Btu as the CAIR target budget rate for 2015 and thereafter. The formula in Rule 822(4)(a)(ii)(B) identifies this same value as the CTER = CAIR target emissions rate. This should be identically identified.
Response: Others have made similar comments. DEQ has made corrections to clarify the rule's intent.

c. A. K. Evans, Director of Air Quality, Consumers Energy
In general the company is supportive of the rules as proposed and offered several editorial or typographical corrections. These are as follows:
Comment: 803(3)(d) -- Throughout R 336.1821 to R 336.1834, the term EGU is essentially used to describe affected units under CAIR that are located within Michigan. Rather than introducing the additional term Michigan EGUs the definition of EGU should simply include the concept that the unit must be located within Michigan. Furthermore, the term Michigan EGU does not accurately reflect the affected units under CAIR because it does not include the concept of cogeneration or solid waste incineration units. Such unit may serve a generator with a nameplate capacity of more the 25 megawatts but they may still be exempt from CAIR and should therefore not be classified as EGUs under R 336.1821 to R 336.1834. With the proposed change to R 336.1803(d), the term Michigan EGUs in R 336.1803(h) is no longer needed and should be removed.
Response: DEQ agrees and has made corrections and modifications to clarify the EGU definitions.
Comment: 803(3)(j) -- The definition of non-EGU should inherently include the concept that any such source must be located within Michigan. Further, this is more consistent with how the term non-EGU is used throughout R 336.1821 to R 336.1834. The definition of EGU for purposes of the NOx Budget Trading Program and the CAIR program are different and units that were classified as EGUs under the NOx Budget Trading Program may not be classified as EGUs under the CAIR program. With the CAIR NOx program essentially replacing the NOx Budget Trading Program, any such unit should be re-classified as non-EGUs.
Response: DEQ agrees and has made corrections and modifications to clarify the non-EGU definitions.
Comment: 803(3)(n) -- Qualifying renewable energy projects would receive allocations from the CAIR NOx ozone season program. Therefore, R 336.1830 to R336.1834 should not be referenced as these rules pertain to the CAIR NOx annual program. For purposes of clarification, the definition of renewable energy sources should specify that the renewable energy sources must be located within Michigan to be eligible to receive allocations.
Response: DEQ agrees and has corrected the typo.
Comment: 821(1)(b) -- For purposes of consistency with 40 C.F.R. Part 97, the term ozone season CAIR NOx unit should be replaced with the term CAIR NOx ozone season unit consistent with the definition in §97.302. Further Michigan is adopting CAIR applicability provisions as contained in the FIP and the reference to §96.304 should accordingly be changed to §97.304. Lastly, EGUs would be included under §97.304 and the rule citation should be changed to R 336.1803(j).
Response: DEQ has made the requested changes to clarify the intent of the rules.
Comment: 821(1)(c) -- Per preceding comments, the rule references and CAIR NOx unit terminology should be revised. Also, the term “renewable source projects” is not defined in R 336.1803 and should be changed to renewable energy projects, consistent with R 336.1803(o). More fundamentally, is it even necessary to state that renewable energy sources and renewable energy projects are CAIR NOx ozone season units? It seems as though actually treating these sources as CAIR NOx ozone season units

could be somewhat problematic, as CAIR NOx ozone season units are required to have permits, designated representatives, etc. It seems as though the owner or operator of a renewable energy source would simply establish a general account for purposes of receiving allocations under R 336.1821 to R 336.1824.
Response: DEQ has made corrections to clarify the rule. After discussion with EPA it is appropriate for renewables to have an authorized account representative, but do not need a permit.
Comment: 821(3) -- With the proposed deletion of the term Michigan EGU, R 336.1821(3) must be revised in order to reference the definition of EGU for the CAIR NOx program.
Response: DEQ agrees and has made the correction to clarify the rule.
Comment: 821(5)(b) -- R 336.1821(5)(a) refers to both annual and ozone season heat input rates of megawatt energy produced, and R 336.1821(5)(b) should also reference both annual and ozone season time periods. Further, R 336.1802 is not applicable after January 1, 2009, and should be replaced with a reference to R 336.1802a.
Response: DEQ agrees and made corrections to clarify the intent of the rule.
Comment: 822(1) -- The term renewable units is not defined and should be replaced with renewable energy sources consistent with R 336.1803(3)(n). Further, the budget amounts described in the rest of the subrule apply to the ozone control period in each calendar year (i.e. the budget amounts are not total for the time periods 2010-2011, 2012-2014, etc). The proposed language is intended to clarify that the budget amounts apply to each calendar year within the designated time frames.
Response: DEQ agrees and made corrections to clarify the intent of the rule.
Comment: 822(4)(a)(i) -- The unit with no applicable NOx emission rate language in (4)(s)(i)(A) is intended to clarify coverage for a so-called grandfathered unit whose installation may have pre-dated any NOx emission limit. The “initial unadjusted allocation of” language is intended to clarify that the units will not necessarily receive the allowances calculated according to the formula (as written, “the units … shall receive allowances”). The initial allocation may later be adjusted in subrule (5). The changes in the table following the equation are intended to clarify what units the various terms are expressed in, the time period for CAIR target emission rate and the appropriate heat input value to be used in the calculation.
Response: DEQ agrees and made corrections to clarify the intent of the rule.
Comment: 822(4)(a)(ii) -- These changes are identical to those in 822(4)(a)(i) except for using the appropriate 2015 and thereafter target emission rate.
Response: DEQ agrees and made corrections to clarify the intent of the rule.
Comment: 823(2)(a) -- The current wording references March 1 of the 2009 ozone control period which does not start until May 1, 2009. This rule should be revised to simply reference March 1, 2009.
Response: DEQ agrees and made corrections to clarify the intent of the rule.
Comment: 823(5) -- Consumers Energy fully supports the re-allocation of allowances that remain in the new source set-aside pool back to the existing EGU and non-EGU pools. However, there are separate pools for the existing EGUs and non-EGUs, and the relative amount of re-allocations to each of these pools must be defined. For purposes of re-allocation, Consumers Energy suggests that any remaining allowances be split between the existing EGU and non-EGU pools based upon the

relative size of each of these pools for a given compliance period. For example, assume that there are 500 allowances remaining in the 2010 new source set-aside pool. The allowances would be re-allocated back to the existing EGU and non-EGU pools as follows: existing EGU pool = 28,321/(28,321+1,309)* 500 = 477.9 (rounds to 478); existing non-EGU pool = 1,309/(28,321+1,309)*500 = 22.1 (rounds to 22).
Response: DEQ agrees with the comment and has modified the language to clarify the rule's intent, although not exactly as proposed.
Comment: 824(3)(a)(i) -- In regards to the hardship allowances, the target NOx emission rate should be consistent with the NOx emission rate used for allocation purposes. In addition, units subject to R 336.1804(4)(g) were required to submit an engineering analysis similar to that required under R 336.1810(4)(f). Therefore, engineering analyses submitted for purposes of R 336.01801(4)(g) should also be eligible for use under R 336.1824(3)(a)(i).
Response: DEQ agrees and has made modifications to clarify the rule's intent.
Comment: 825(2) -- Renewable energy sources and renewable energy projects are not affected units under the federal CAIR program. Therefore, such units will not have compliance accounts. While the owners and operators of such units could establish general accounts for the purpose of receiving allowance allocation, the general accounts would not be tied back to the associated units. Thus a renewable energy source or renewable energy project will not have an authorized account representative.
Response: DEQ has made corrections to clarify the rule. After discussion with EPA it is appropriate for renewables to have an authorized account representative, but do not need a permit.
Comment: 825(3)(a) -- By definition, renewable energy sources and renewable energy projects are non-emitting. Therefore, it does not seem necessary to mention a permit to install which would not apply to non-emitting sources.
Response: DEQ has made corrections to clarify the rule. After discussion with EPA it is appropriate for renewables to have an authorized account representative, but do not need a permit.
Comment: 825(4) and (5) -- It is the owner(s) or operators(s) of the renewable energy source or project who would request allowances, not the actual unit or group of units. Furthermore, an individual renewable energy source or project will not have an authorized account representative as the unit or group of units would not be an affected source under the federal CAIR program. Lastly, it is each physical renewable energy source or project which should only be eligible to receive allocations for three consecutive ozone seasons, not the owner(s) or operator(s) of such sources.
Response: DEQ agrees and has modified the language to clarify the intent.
Comment: 825(6) -- Again, Consumers Energy fully supports the re-allocation of allowances that remain in the renewable set-aside pool back to the existing EGU and non-EGU pools, but the relative amount of re-allocation to each of these separate pools must be defined. For purposes of re-allocation, Consumers Energy suggests that any remaining allowances be split between the existing EGU and non-EGU pools based upon the relative size of each of these pools for a given compliance period.
Response: DEQ agrees with the comment and has modified the language to clarify the rule's intent, although not exactly as proposed.
Comment: 830(3)(a) -- Allowances for the CAIR NOx annual control period must be distributed starting in 2009 not 2010. Other comments, same as for Rule 822(4)(a)(i) …

The units with no applicable NOx emission rate language in (3)(a)(i) is intended to clarify coverage for any so-called grandfathered unit whose installation may have pre-dated any NOx emission limit. The initial unadjusted allocation language is intended to clarify that the units will not necessarily receive the allowances calculated according to the formula (as written, "the units, shall receive allowances"). The initial allocation may later be modified in subrule (5). The changes in the table following the equation are intended to clarify what units the various terms are expressed in.
Response: DEQ corrected the typo of 2010 with 2009 as requested. The rule was further modified as suggested to clarify the rule's intent.
Comment: 830(3)(b) -- These changes are essentially identical to those in 830(3)(a) except for using the appropriate 2015 and thereafter target emission rate.
Response: DEQ agrees and modified the language as suggested to clarify the rule's intent.
Comment: 832(2)(b) -- Non-EGUs are not included in the CAIR NOx annual program and the reference to non-EGU should therefore be deleted.
Response: DEQ agrees and corrected the typo. The reference has been removed.
Comment: 832(2)(c)(i) -- The heat input rate used for the allocation should be consistent with the heat input rate used for allocations under Rule 830.
Response: DEQ agrees with the comment; however, does not believe any modifications are necessary as DEQ interprets the current wording to be the same as under Rule 822.
Comment: 832(3)(a)(i) and (b) -- In regards to the hardship allowances, the target NOx emission rate should be consistent with the NOx emission rate used for allocation purposes. In addition, the initial three-year allocation period will end December 31, 2011, not September 30, 2011.
Response: DEQ agrees and corrections have been made.
d. Douglas Aburano, Environmental Engineer, EPA Region 5
Comment: 803(3) -- Michigan needs to supplement the definition of "Commence commercial operation" with language stating that, for units not serving a generator, the commence operation date is also the commenced commercial operation date. This is important because monitoring system certification deadlines are based on the date of commencement of commercial operation, and some CAIR NOx ozone season units in Michigan may not serve generators.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 803(3) – It appears that Michigan intends to allocate allowances under the CAIR NOx ozone season trading program to Michigan EGUs and Michigan non-EGUs, as well as to units that are CAIR NOx ozone season units under 40 CFR 97.304. Consequently, Michigan needs to define "new" Michigan non-EGU and "existing" Michigan non-EGU, as this terminology is used in allocating allowances under that trading program. In addition, the definition in R 336.1803(d) should be clarified to read as follows: "'Electric generating unit' or 'EGU' means, for purposes of the CAIR NOx ozone season

trading program, a CAIR NOx ozone season unit under 40 CFR 97.304, a Michigan EGU for purposes of the CAIR NOx annual trading program, a CAIR NOx unit under 40 CFR 97.104." EPA also suggests that, for clarity, Michigan should consistently define and use either the term "Michigan non-EGU" or the term "non-EGU" in the regulations. Similarly, EPA suggests that Michigan use consistent terminology when referring to "an existing EGU", "a new EGU" (rather than also referring to it as, e.g., "a new EGU CAIR NOx ozone season unit") and to "newly affected EGU" (rather than also referring to it as, e.g., "a newly-affected CAIR NOx ozone season EGU").
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 803(3)(f) – This definition needs to apply for purposes of determining the applicability of the rule to Michigan EGUs , as well as Michigan non-EGUs.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 803(3)(h) – Michigan needs to revise this definition to incorporate the applicability language for EGUs in Michigan's NOx SIP Call rule. In expanding the applicability provisions of EPA's CAIR NOx ozone season model rule to include all units included in Michigan's NOx SIP Call trading program, Michigan's rule must cover all units that are exempt under the CAIR FIP (e.g., certain cogeneration units) but that are subject to Michigan's NOx SIP Call rule. See 40 CFR 51.121(ee)(1). Consequently, "Michigan EGUs" needs to be defined as units that are not CAIR NOx ozone season units under 40 CFR 97.304 and: "(i) For units in the Michigan fine grid zone that commenced operation before January 1, 1997, a unit serving a generator during 1995 or 1996 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale. "(ii) For units in the Michigan fine grid zone that commenced operation on or after January 1, 1997 and before January 1, 1999, a unit serving a generator during 1997 or 1998 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale. "(iii) For units in the Michigan fine gird zone that commence operation on or after January 1, 1999, a unit serving a generator at any time that has a nameplate capacity of more than 25 megawatts and produces electricity for sale." In addition, Michigan needs to add a statement in the definition that, for purposes of this definition, the term "unit" is defined as set forth in Michigan's NOx SIP Call rule.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 803(3)(j) – Michigan needs to revise this definition to: limit the units involved to those that are in the Michigan fine grid zone and are not CAIR NOx ozone season units under 40 CFR 97.304. In addition, Michigan needs to add a statement in the definition that, for purposes of this definition, the term "unit" is defined as set forth in Michigan's NOx SIP Call rule.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 821(1)(a) -- Remove the word "Annual." Part 97 defines "CAIR NOx units"

as those subject to the annual CAIR NOx trading program. In addition, the reference to 40 CFR part 97 should be changed to refer to 40 CFR 97.104.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 821(1)(b) -- Change the phrase "Ozone season CAIR NOx units" to read "CAIR NOx ozone season units" to be consistent with part 97 definitions. In addition, the reference to 40 CFR part 97 should be changed to refer to 40 CFR 97.304. Also, change reference to 40 CFR 96.304 to refer to 40 CFR 97.304.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 821(2) -- This provision should refer to a Michigan source subject to the requirements of R 336.1821(a) or (b), not 40 CFR 97.104 or 97.304, in order to include the Michigan EGUs and Michigan non-EGUs not covered under the CAIR NOx ozone season model rule.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 821(3) – This provision exempts from the CAIR NOx annual and ozone season trading programs any Michigan EGU that stops burning fossil fuel after January 1, 2008, for the production of electricity. Under 40 CFR 51.123(o)(2) and (p) and (aa)(2) and (ee), Michigan cannot make this change in the applicability provisions in the EPA model trading rules and the CAIR FIP and still participate in the EPA-administered trading programs. The exemption provision in 1821(3) must be removed.
Response: DEQ has removed the statement.
Comment: 821(4) – It is unclear to what units these provisions on fuel adjusted allocations apply. For example, it is unclear whether Michigan intends that the provisions apply to Michigan non-EGUs and what is intended by the reference to "cogeneration unit," which term is not defined.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 821(5) – It seems that these provisions should apply to Michigan EGUs and Michigan non-EGUs, as well as to CAIR NOx ozone season units.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 821(7) – It is unclear why 40 CFR 96.30 and 96.31 (relating to compliance certifications) are referenced. It seems that 40 CFR 96.54 (addressing deductions for excess emissions) should be referenced instead. In addition, the provision should state that the deductions should be from 2009 "CAIR NOx ozone season allowances".
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 822(3)(a) – The phrase "A 3-year allocation that is 3 years in advance of the ozone season control period" needs to be revised to read "A 3-year allocation that is 3 years in advance of the 2010 ozone season and 4 years in advance of each subsequent ozone season control period." The dates in R 336.1822(3)(a) (ii) and (iii) are correct, but they are generally 4 years in advance. For example, the allocation made on April 30, 2007, is for the 2010 ozone season, which is in the year 3 years after 2007, and for the 2011 ozone season, which is in the year 4 years after 2007.
Response: DEQ has modified the language to clarify the rule's intent and address

EPA's concerns.
Comment: 822(6) – EPA suggests that the phrase "single highest heat input" be revised to read "single highest ozone season heat input."
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 823(4)(b) – EPA notes that Michigan's rule does not define "maximum design capacity". EPA suggests that, for clarity, a definition should be added. For example, Michigan's rule does not state whether the units of measure for maximum design capacity are in Megawatts steam or Megawatts electricity. The rule also does not state whether the output values (MWh) are gross or net values. In R 336.1823(4)(c), the rule seems to limit MWh to electricity, but does not specify gross or net.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 824(2)(a) – Michigan does not have any allowances available for allocation for 2009 through the hardship set-aside. Consequently, Michigan needs to add the following at the end of the first sentence of R 336.1824(2)(a): "starting in 2010."
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 824(2)(c)(i) – EPA suggests that the phrase "single highest heat input" be revised to read "single highest ozone season heat input."
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 824(2)(c)(iii) -- The phrase "a 3-year allocation that is 3 years in advance of the ozone season control period" needs to be revised to read "a 3-year allocation that is 3 years in advance of the 2010 ozone season and 4 years in advance of each subsequent ozone season control period".
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 825(1) -- Michigan does not have any allowances available for allocation for 2009 through the renewable set-aside. Consequently, Michigan needs to add the following at the end of the first sentence of R 336.1825(1): "starting in 2010."
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 825(3)(b) – EPA notes that Michigan's rule does not define "maximum design capacity." EPA suggests that, for clarity, a definition should be added. For example, Michigan's rule does not state whether the units of measure for maximum design capacity are in Megawatts steam or Megawatts electricity. The rule also does not state whether the output values (MWh) are gross or net values. In R 336.1825(3)(c), the rule seems to limit MWh to electricity, but does not specify gross or net.
Response: DEQ has modified the language to clarify the rule's intent by converting the maximum design to nameplate which addresses EPA's concerns.
Comment: 830(2) -- The phrase "A 3-year allocation that is 3 years in advance of the ozone season control period" needs to be revised to read "A 3-year allocation that is 2 and 3 years in advance of the 2009 and 2010 ozone seasons respectively and 4 years in advance of each subsequent ozone season control period." The dates in

R 336.1830(2)(b) and (c) are correct, but they are generally 4 years in advance. For example, the allocation made on April 30, 2007, is for the 2009 and 2010 ozone seasons, which are in the years 2 and 3 years after 2007, and for the 2011 ozone season, which is in the year 4 years after 2007.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 831(2)(b) -- EPA notes that Michigan's rule does not define "maximum design capacity." EPA suggests that, for clarity, a definition should be added. For example, Michigan's rule does not state whether the units of measure for maximum design capacity are in Megawatts steam or Megawatts electricity. The rule also does not state whether the output values (MWh) are gross or net values. In R 336.1831(2)(c), the rule seems to limit MWh to electricity, but does not specify gross or net.
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 832(2)(c)(iii) -- The phrase "a 3-year allocation that is 3 years in advance of the ozone season control period" needs to be revised to read "a 3-year allocation that is 2 and 3 years in advance of the 2009 and 2010 ozone seasons respectively and 4 years in advance of each subsequent ozone season control period."
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.
Comment: 833(3)(b) – Michigan's compliance supplement pool provisions need some clarification in order to be consistent with 40 CFR 51.123(e)(4)(iii)(B)(2). R 336.1833(3)(b)(i) should be revised to read: "A showing that it would not be possible for the owners and operators of the unit to obtain sufficient amounts of electricity from other electric generation facilities, during the installation of control technology at the unit for compliance with the CAIR NOx emissions limitation, to prevent such undue risk." Similarly, R 336.1833(3)(b)(ii) should be revised to read: "A showing that it would not be possible for the owners and operators of the unit to obtain sufficient allowances under subrule (2) or from other sources or persons to prevent such undue risk."
Response: DEQ has modified the language to clarify the rule's intent and address EPA's concerns.

The following comments received involve requested modifications to the rules. DEQ did not agree with the comments and no changes to the rules were made.
e. Michael Weber, Environmental Services, CMS Enterprises Co.
Comment: 822(3)(a)(i) -- It is unlikely these rules will become effective prior to April 30, 2007, but even if they do, the regulated community will need time after the effective date of the rule to, for example, apply for hardship allowances, which are to be allocated under Rule 824(2)(c)(iii) in 3-year blocks in accordance with this Rule 822(3). However, in accordance with Rule 824(1), such hardship requests must be made at least "30 days prior to the deadline for departmental submittals to the EPA as described in R336.1822." If DEQ wants any time to process such hardship allocation requests, we suggest that 60 days after the effective date of the rule is the minimum needed prior to the initial submittal.

Response: In order to avoid the EPA from populating source accounts with the budgets as determined in the FIP, DEQ needs to keep the language as noted in the rules. DEQ will be submitting the allocations prior to when the final state rule is approved. No changes will be made.
Comment: 823(2)(b) **--** The fuel adjustment factor was left out of this calculation.
Response: DEQ disagrees, no changes were made. The original NOx SIP Budget program did not utilize the fuel adjustment factors and current 2009 NOx budgets were not calculated in that manner for the existing units. Therefore DEQ believes for the sake of consistency that it is not appropriate to use the fuel adjustment factor for the "newly-affected" sources. No changes will be made.
Comment: 824(2)(c)(ii) **--** Some units may not be required to monitor in accordance with 40 CFR 75 requirements prior to 2008.
Response: DEQ disagrees, no changes were made. All sources will be required to report their NOx emission rates to the EPA in a format they specify. The rule does not specify "monitored" emission rates. For example, sources are allowed under Part 75 to submit data as a low mass emitter.
Comment: 830(2)(a) -- Same comment as for Rule 822(3)(a)(i)… It is unlikely these rules will become effective prior to April 30, 2007, but even if they could, the regulated community will need time after the effective date of the rule to, for example, apply for hardship allowances, which are to be allocated under Rule 832(2)(c)(iii) in 3-year blocks in accordance with this Rule 830(2). However, in accordance with Rule 832(1), such hardship requests must be made at least "30 days prior to the deadline for departmental submittals to the EPA as described in R 336.1830." If DEQ wants any time to process such hardship allocation requests, we suggest that 60 days after the effective date of the rule is the minimum needed prior to the initial submittal.
Response: In order to avoid the EPA from populating source accounts with the budgets as determined in the FIP, DEQ needs to keep the language as noted in the rules. DEQ will be submitting the allocations prior to when the final state rule is approved. No changes will be made.
Comment: 832(2)(c)(ii) -- Same comment as for Rule 824(2)(c)(ii)…Some units may not be required to monitor in accordance with 40 CFR 75 requirements prior to 2008.
Response: DEQ disagrees, no changes were made. All sources will be required to report their NOx emission rates to the EPA in a format they specify. The rule does not specify "monitored" emission rates. For example, sources are allowed under Part 75 to submit data as a low mass emitter. No changes will be made.
Comment: 833(3)(b) **--** The newly-affected units are in a unique situation with respect to all other affected units around the country – they are subject to the CAIR ozone-season program, but receive no 2009 allocation of ozone-season NOx allowances, because they were not part of the NOx SIP Call program (either due to geographic location within Michigan or due to the difference in definition of "fossil fuel" between the NOx SIP Call and CAIR). We should not be penalizing these units simply due to these unlucky circumstances. Rule 833(3) is intended to address the shortfall of allowances that may occur for these newly-affected units, if they are unable to obtain sufficient allowances from the ozone-season new unit pool under Rule 823(2). As written, Rule 833(3)(b) is more stringent than the compliance supplement pool requirements in 40 CFR 96.143(c)(2), which require a unit to make one demonstration or the other, but not both. This, combined with the failure to include economic

considerations, creates an insurmountable burden for these units. It can be argued that these units could always buy electricity or allowances from someone else – it's just a question of how much it costs. The proposed language is intended to clarify that these newly-affected units should be required to make a reasonable demonstration to qualify for the supplemental 2009 allowances.
Response: DEQ disagrees, the language used was dictated by EPA, no changes were made.
f. Kristine Krause, VP Environmental, WE Energies
Comment: Raised concerns about the newly affected EGUs and applicability under Michigan's Rule 801 provisions. Requested rule language stating single rule applicability.
Response: DEQ believes that Rule 801(14) is sufficient. Rule 801(14) states that sources that are subject to the federal NOx programs are not subject to Rule 801. No changes were made.
g. William Rogers, Senior Technological Specialist, Detroit Edison Company
Comment: 803(3)(o) -- Geographic areas should be specifically identified. Since counties are used to specifically identify the geographical area for the Michigan fine grid zone in (3)(i), we recommend identification of the geographical area of (3)(o) to also be identified as within the same county.
Response: DEQ disagrees, no changes were made. The definition of geographic area is the same as what is used to determine stationary source status under EPA's Title V permit program. Some projects may span two counties and yet a unit may be immediately adjacent to others in a different county and under the definition of stationary source be considered one geographic area.
Comment: 821(3) -- It has been recognized that EPA included Michigan's biomass units in the program without including their heat input values in the determination of the budgets. DEQ has agreed to exempt any biomass units that restrict their fuel usage to biomass only … We support this exemption and suggest no further delay in implementation of this rules package, possibly resulting in EPA imposition of the Federal Implementation Plan because of this exemption.
Response: CAMD has indicated in their formal comments that the provision cannot be approved. DEQ has removed the exemption from the rules, and the biomass units have been added to the allocation tables as appropriate.
h. A. K. Evans, Director of Air Quality, Consumers Energy
Comment: 803(3)(o) -- Again, R 336.1830 to R 336.1834 should not be referenced as these rules pertain to the CAIR NOx annual program. It must be specified that the renewable energy projects to be aggregated are all located in Michigan and to constitute a project each source should be aggregated into the electric transmission system at a single common point of transfer. The term same geographic area is so broad as to be essentially meaningless unless it is further qualified.
Response: DEQ disagrees, no changes were made. The definition of geographic area is the same as what is used to determine stationary source status under EPA's Title V permit program.
Comment: 821(4) -- Subsequent rules refer to fuel adjustment factors but the term is

not currently defined in R 336.1803 to R 336.1834. The proposed language is intended to clarify that the fuel adjustment factors are consistent with the coefficients specified in R 336.1821(4). Furthermore, for multi-fueled EGUs the heat input weighted fuel adjustment factor (FAF) should be consistent the two-year period used to derive the heat input in accordance with R 336.1822(6) of R 336.1830(4), The proposed revisions are designed to clarify the application of the FAFs and the deviation of the FAFs for multi-fueled units.
Response: The FAFs have been clarified in the definitions under Rule 803; however, DEQ disagrees with the proposed change in multi-fueled units and has not made the suggested changes. Since the “5-year window” used to determine the allowances is 3 to 4 years in advance of the actual allocation, facilities are capable of submitting the percentage of multi-fuels used for each year of the window leaving DEQ with sufficient time to use the percentage in calculations of the allowances.
Comment: 822(6) -- For multi-fueled EGUs the two highest ozone season heat inputs may not correspond to the highest adjusted heat input when considering the weighted FAFs. Therefore, such units should be allowed to use any two of the ozone control period heat inputs within the appropriate five-year period in order to determine the heat input used for allocations.
Response: DEQ disagrees with the proposed change in multi-fueled units and has not made the suggested changes. Since the “5-year window” used to determine the allowances is 3 to 4 years in advance of the actual allocation, facilities are capable of submitting the percentage of multi-fuels used for each year of the window leaving DEQ with sufficient time to use the percentage in calculations of the allowances.
Comment: 823(2)(b) -- The fuel adjustment factor was left out of this calculation. Furthermore the heat input rate used for this allocation should be consistent with the heat input rate used for allocation under Rule 822. With the proposed revisions, Rule 823(3)(c) should be deleted.
Response: DEQ disagrees with adding in the fuel adjustment factors and for removal of Rule 823(3)(c). The newly affected units should receive ozone season allowances based on the same methodology as the existing units for 2009. The 2009 allowances were not calculated under the NOx SIP Budget using fuel adjustment factors.
Comment: 824(2)(c)(i) -- The heat input rate used for the allocations should be consistent with the heat input rate used for allocations under Rule 822.
Response: DEQ agrees with the comment; however, does not believe any modifications are necessary as DEQ interprets the current wording to be the same as under Rule 822.
Comment: 825(3)(b) -- EGUs and non-EGUs must have allowances for purposes of compliance (starting with initial operation) and these allowances represent an immediate operating cost. In contrast, renewable energy sources and projects are non-emitting sources that do not need any allowances to cover their operation. Due to this basic difference, it is not necessary to award allowances to renewable energy sources and projects based upon projected operation. Rather allowances to these types of sources should always be based upon actual production. Further, we suggest that allowances be awarded on gross generation (consistent with the proposed allocation method for new EGUs. With the proposed revisions to Rule 825(3)(b), Rule 825(3)(c) should be deleted.
Response: DEQ disagrees and will not modify the rules. The process was negotiated

during the workgroup.
i. David Gard, Energy Program Director, Michigan Environmental Council Richard Vander Veen, President Mackinaw Power Debra Jacobson, Owner, DJ Consulting LLC Alden Hathaway, Director EcoPower Programs, Environment Resources Trust Colin High, Chairman, Resource Systems Group
In general the entities were supportive of the rules, in particular the inclusion of a renewable set-aside pool. However, they did offer minor changes or corrections. These are as follows:
Comment: Include a set-aside of NOx allowances for renewable energy sources and projects in its annual trading rule.
Response: DEQ understands the concerns raised. However, as noted during workgroup negotiations, the DEQ believes that having a set-aside for the ozone season only is appropriate.
Comment: Increase the amount of allowances for ozone season renewable energy set-asides to at least three percent of the total EGU allowance pool or include a reassessment provision.
Response: DEQ understands the concerns raised. However, as noted during workgroup negotiations, the DEQ believes that having a set-aside at the current level is appropriate.
Comment: Allow smaller renewable energy projects into the program through aggregation.
Response: DEQ understands the concerns raised. However, as noted during workgroup negotiations, the DEQ believes that having a set-aside as currently defined for projects and sources is appropriate.
Comment: By April 30, 2011, the DEQ should complete a report reviewing the appropriateness of the future size of the renewable energy set-aside program and any refinements needed. Increased deployment of renewable energy also would be consistent with findings of the Michigan Public Service Commission's recent 21st century energy plan report and enactment of the Michigan Renewable Energy Standard, Senate Bill 213 or House Bill 4562.
Response: DEQ believes that since the statement is a policy decision, it is not appropriate to address within the rules language.
j. Douglas Aburano, Environmental Engineer, EPA Region 5
Comment: 823(4)(a) – EPA suggests that Michigan clarify its rule to indicate whether a separate request must be submitted for each year for which new unit allowances are sought.
Response: DEQ believes the language in the rule addresses EPA's concerns and after a discussion with EPA, they are in agreement; therefore no changes are necessary.
Comment: 831(2)(a) – EPA suggests that Michigan clarify its rule to indicate whether a separate request must be submitted for each year for which new unit allowances are sought.
Response: DEQ believes the language in the rule addresses EPA's concerns and after a discussion with EPA, they are in agreement; therefore no changes are necessary.

The following comments received indicated support of the rules. No changes to the rules were made.
k. Jim Weeks, General Counsel, Michigan Municipal Electric Association (MMEA)
In general the company is supportive of the rules as proposed. These are as follows:
Comment: MMEA and its municipal members support and commend DEQ for establishing a CAIR NOx rule that recognizes the disproportionate costs and impacts of controls on small municipal systems and units. DEQ's establishment of a "hardship" program to support these small units will make a critical difference for our communities. MMEA and its municipal members support and appreciate the establishment of the hardship allowance program for our entities, at proposed Rule 824 and Rule 832. These proposed rules recognize the cost and technical infeasibility of traditional compliance methods for our small systems and units. At the same time, these rules require the electric system to demonstrate that it is a small business, and that pollution control costs are excessive and prohibitive based on engineering and cost studies.
Response: DEQ appreciates the support.
Comment: MMEA and its members also encourage DEQ and the State of Michigan to continue to move this rules package forward expeditiously. Michigan entities have less than three years to be ready for compliance with this rule, and the rule should be finalized so that Michigan can begin compliance activities. Most importantly, delays in the Michigan CAIR rulemaking could expose the state to the possibility of EPA imposing a Federal Implementation Plan in lieu of the Michigan rule. Such a Federal Implementation Plan would imperil many of the best aspects of the rule that have been developed through cooperative Michigan stakeholder efforts to match the needs of our state – including the hardship allowance program.
Response: DEQ agrees and will do everything we can to move the package forward expediently.
l. Kristine Krause, VP Environmental, WE Energies
In general the company is supportive of the rules as proposed. These are as follows:
Comment: Supports DEQ's decision to participate in the EPA CAIR trading program as this provides cost-effective emission reductions and tangible benefits in terms of streamlining programs and regulatory requirements. Supports DEQ's decision to use CAMD database information to calculate the allowances but requests that the revision of the data does not delay the rulemaking process. Supports DEQ's decision to create a set-aside pool for the newly affected EGUs as this alleviates the inequity among CAIR–affected sources.
Response: DEQ appreciates the support.

The following comments received involved substantial corrections to the rules. DEQ made the corrections and does not believe these changes adversely impact the regulated community or the general public
m. Michael Weber, Environmental Services, CMS Enterprises Co.
Comment: 821(3) -- Unless DEQ has received clear direction from EPA's Clean Air

Market Division (CAMD) that it will allow the exemption, and clear indication from an affected EGU that it wishes to apply for the exemption by the time DEQ submits the 2009 – 2011 allocations to EPA, DEQ must allocate allowances to all EGUs. If the entire budget for EGUs is allocated for example, just to the non-biomass units, it will be very difficult for DEQ to "take back" a few from each EGU to reinstate the allocation to the affected biomass units, should EPA later disapprove the exemption. On the other hand, if the allowances are allocated to all units, it will be fairly straightforward to reallocate them out to the non-exempted EGUs, should any units claim the exemption. The proposed language in the last sentence of paragraph (a) is intended to accomplish this result. Again, there may be other ways of doing this – we are just looking for assurance that our biomass units would have an allocation of allowances should EPA disapprove the exemption, or we elect not to use it even if it is approved.
Response: CAMD has indicated in their formal comments that the provision cannot be approved. DEQ has removed the exemption from the rules, and the biomass units have been added to the allocation tables as appropriate.
Comment: 825(7) – CMS suggested adding a new subrule. This is needed in case the renewable pool is oversubscribed.
Response: DEQ agrees and has added the additional language to clarify the process.
n. William Rogers, Senior Technological Specialist, Detroit Edison Company
Comment: 803(3)(h) through (l) -- Detroit Edison's Harbor Beach Power Plant is located outside the identified Michigan fine grid zone. While also geographically outside the fine grid zone for NOx SIP Call purposes, Harbor Beach Power Plant was at that time specifically identified as an affected source. By definition with the currently proposed Rule 803, the plant would be identified as a newly-affected EGU. Since Harbor Beach Power Plant is already an affected source under the NOx SIP Call, it should also be specifically identified as an affected source for the purposes of this rule.
Response: DEQ agrees and has added the following statement to Rule 803(3)(j): This definition excludes the Harbor Beach Power Plant which was previously included as an EGU in the NOx SIP Budget trading program and is considered existing for the purposes of CAIR NOx ozone season program.
o. A. K. Evans, Director of Air Quality, Consumers Energy
Comment: 823(3)(a) and (b) -- The term oxides of nitrogen unit is not defined and should be replaced with the term non-EGU. The allocation formula for new non-EGUs is incorrect, as the final units of the multiplication approach would be "ton per hour," not tons per control period. The allocation has to be based on the heat input during the ozone season control period. Unfortunately there are not provisions for determining the appropriate ozone season heat input during the first year that allocations are requested or any of the subsequent years before the unit becomes an existing unit. The proposed language mirrors the new unit allocation approach for EGUs and is designed to provide clarification. Lastly, a provision should be added to address the fact that the allocation procedures of R 336.1822 apply once the new non-EGU becomes an existing unit.
Response: DEQ had corrected the term oxides of nitrogen unit to non-EGU to clarify the rule and has added the language similar to what was used in the NOx SIP Budget Program to clarify the rule's intent.

Comment: 823(4)(a) and (b) -- The term oxides of nitrogen unit is not defined and should be replaced with the term EGU. In both of the allocation equations the NOx allocation factor must be specified on a gross or net basis. We suggest that the gross electrical output be used for allocations purposes. This is consistent with the output based NOx emission limit in 40 C.F.R. part 60 Subpart Da. Furthermore, units that use all of their heat input for electrical generation are required to monitor, record and report gross electrical output pursuant to 40 C.F.R. Part 75. **General Comment**: 40 C.F.R. Part 60, Subpart Da, indicates that an output based limit of 1.0 pounds per megawatt hour (lb/MWh) is approximately equivalent to an input based limit of 0.11 pound per million Btu. It is possible that a new unit will have a NOx emission limitation of less than 1.0 lb/MWh due to BACT, LAER, etc. Should the allocation factor for new units be the more stringent of 1.0 lb/MWh or the permitted emission limit, the average of 1.0 lb/MWh and the emission limit, similar to the allocation concept for existing units or some other method?
Response: DEQ replaced the term oxides of nitrogen units with the words EGU to correct the error and added the term gross to clarify the rule's intent. However, the 1.0 lb/MWh emission rate was negotiated during the workgroup efforts and will remain in the rule as is.
Comment: 831(2)(a) through (c) -- The term oxides of nitrogen unit is not defined and should be replaced with the term EGU. In both of the allocation equations the NOx allocation factor must be specified on a gross or net basis. We suggest that the gross electrical output be used for allocations purposes. This is consistent with the output based NOx emission limit in 40 C.F.R. part 60 Subpart Da. Furthermore, units that use all of their heat input for electrical generation are required to monitor, record and report gross electrical output pursuant to 40 C.F.R. Part 75. **General Comment**: 40 C.F.R. 60, Subpart Da, indicates that an output based limit of 1.0 lb/MWh is approximately equivalent to an input based limit of 0.11 lb/mm Btu. It is possible that a new unit will have a NOx emission limitation of less than 1.0 lb/MWh due to Best Available Control Technology (BACT), Lowest Achievable Emission Rate (LAER), etc. Should the allocation factor for new units be the more stringent of 1.0 lb/MWh or the permitted emission limit, the average of 1.0 lb/MWh and the emission limit, similar to the allocation concept for existing units or some other method?
Response: DEQ has corrected the term oxides of nitrogen unit to EGU to clarify the rule and has added the term gross to clarify the rule's intent. However, the 1.0 lb/MWh emission rate was negotiated during the workgroup efforts and will remain in the rule as is.

Name of person completing this report:

Mary Ann Halbeisen

Date report completed:

May 9, 2007

(SOAHR-JCAR June 2005)

THE GRAND RAPIDS
PRESS
Be someone who gets it.

STATE OF MICHIGAN,
COUNTY OF KENT } SS.

The Advertising Director of THE GRAND RAPIDS, PRESS , a newspaper published in the County of Kent, and circulated throughout West Michigan, being duly sworn, deposes and says that the following advertising was inserted.

February 23,2007

Stin S. Westphal

Advertising Director

Sworn and subscribed before me this 23rd day of

February A.D. 2007

Monika R. Dauksts-Strautnieks

NOTARY PUBLIC, KENT COUNTY, MI

My commission expires:

MONIKA R. DAUKSTS-STRAUTNIEKS
Notary Public, State of Michigan
County of Kent
My Commission Expires July 27, 2012
Acting in the County of Kent

NOTICE OF PUBLIC HEARING DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION

The Michigan Department of Environmental Quality (DEQ), Air Quality Division, will conduct a public hearing on proposed administrative rules promulgated pursuant to Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (Act 451); R 336.1802a, R 336.1803, R 336.1821 to R 336.1826, and R 336.1830 to R 336.1834. These rules are being developed to meet requirements of the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR) to reduce transported emissions of oxides of nitrogen from electric generating units and large non-electric generating units. The rules will be submitted to the EPA as part of the Michigan ozone State Implementation Plan upon final promulgation.

The public hearing will be held on April 2, 2007, at 1:00 p.m., in the Constitution Hall, ConCon Conference Room, Atrium South, 525 West Allegan Street, Lansing, Michigan.

Copies of the proposed rules (SOAHR 2005-037EQ) can be downloaded from the Internet at: http://www.michigan.gov/deqair. These rules can also be downloaded from the Internet through the State Office of Administrative Hearings and Rules at http://www.michigan.gov/orr. Copies of the rules may also be obtained by contacting the Lansing office at:

Air Quality Division
Michigan Department of
Environmental Quality
P.O. Box 30260
Lansing, Michigan 48909-7760
Phone: 517-373-7045
Fax: 517-241-7499
E-Mail: halbeism@Michigan.gov

All interested persons are invited to attend and present their views. It is requested that all statements be submitted in writing for the hearing record. Anyone unable to attend may submit comments in writing to the address above. Written comments must be received by 5:00 p.m. on April 2, 2007.

Persons needing accommodations for effective participation in the meeting should contact the Air Quality Division at 517-373-7045 one week in advance to request mobility, visual, hearing, or other assistance.

This notice of public hearing is given in accordance with Sections 41 and 42 of Michigan's Administrative Procedures Act, 1969 PA 306, as amended, being Sections 24.241 and 24.242 of the Michigan Compiled Laws. Administration of the rules is by authority conferred on the Director of the DEQ by Sections 5503 and 5512 of Act 451, being Sections 324.5503 and 324.5512 of the Michigan Compiled Laws, and Executive Order 1995-18. These rules will become effective immediately after filing with the Secretary of State.

G. Vinson Hellwig, Chief
Air Quality Division

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AFFIDAVIT OF PUBLICATION
COMMUNITY NEWSPAPERS, INC.
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State of Michigan, County of Ingham

IN THE MATTER OF: NOTICE

DEPT OF ENVIRONMENTAL QUALITY

ANN LYON

Being duly sworn, says that he/she is authorized by the publisher of Lansing State Journal., to swear that a certain notice, a copy of which is annexed here to, was published in the following publication:

1. Published in the English language for the dissemination of general and/or legal news, and
2. Has a bonfide list of paying customers or has been published at least once a week in the same community without interruption for at least 2 years, and
3. Has been established, published and circulated at least once a week without interruption for at least one (1) year in the community where the publication is to occur.

LANSING STATE JOURNAL 2/23/07

Ann Lyon

Ann Lyon

SUBSCRIBED AND SWORN TO BEFORE ME THIS 23RD

DAY OF FEBRUARY, 2007

CARRIE A. SAVAGE
NOTARY PUBLIC, STATE OF MICHIGAN, COUNTY OF EATON
MY COMMISSION EXPIRES: SEPTEMBER 4, 2007
ACTING IN THE COUNTY OF EATON

Carrie Savage

LSJ- 2-31

NOTICE OF PUBLIC HEARING
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AIR QUALITY DIVISION

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G. Vinson Hellwig, Chief
Air Quality Division

LE-2-31 2/23/07

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G. Vinson Hellwig, Chief
Air Quality Division

1 time
2-23-2007

County of Oakland }
STATE OF MICHIGAN, } ss.

.....Mary Ward.....being duly sworn, deposes and says that I am the.....Legal Rep.....of THE OAKLAND PRESS, a newspaper printed and circulated daily in Oakland County, Michigan, and that I held such position during the publication of the notice hereto annexed; that a notice of.....

.....public notice.....
of which the annexed notice is a true copy, was published in the said OAKLAND PRESS.....

.....once.....immediately preceding the 24 of February that the annexed printed copy of said notice was taken from the said newspaper. That the dates of

publication of said notice were.....

.....February 23, 2007.....
and further deponent sayeth not.

.....Mary Ward.....

Subscribed and sworn to before me this.....23.....day of

.....February.....A.D. 2007

.....Tina M Crown.....
NOTARY PUBLIC, OAKLAND COUNTY, MICHIGAN

TINA M. CROWN
NOTARY PUBLIC LAPEER CO., MI
MY COMMISSION EXPIRES Mar 30, 2008

acting in Oakland Cty

NOTICE OF PUBLIC HEARING
DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

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G. Vinson Hellwig, Chief
Air Quality Division

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DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

The Michigan Department of Environmental Quality (DEQ), Air Quality Division, will conduct a public hearing on proposed administrative rules promulgated pursuant to Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (Act 451); R 336.1802a, R 336.1803, R 336.1821 to R 336.1826, and R 336.1830 to R 336.1834. These rules are being developed to meet requirements of the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR) to reduce transported emissions of oxides of nitrogen from electric generating units and large non-electric generating units. The rules will be submitted to the EPA as part of the Michigan ozone State Implementation Plan upon final promulgation.

The public hearing will be held on April 2, 2007, at 1:00 p.m., in the Constitution Hall, ConCon Conference Room, Atrium South, 525 West Allegan Street, Lansing, Michigan.

Copies of the proposed rules (SOAHR 2005-037EQ) can be downloaded from the Internet at: http://www.michigan.gov/deqair. These rules can also be downloaded from the Internet through the State Office of Administrative Hearings and Rules at http://www.michigan.gov/orr. Copies of the rules may also be obtained by contacting the Lansing office at:

Air Quality Division
Michigan Department of Environmental Quality
P.O. Box 30260
Lansing, Michigan 48909-7760
Phone: 517-373-7045
Fax: 517-241-7499
E-Mail: halbeism@Michigan.gov

All interested persons are invited to attend and present their views. It is requested that all statements be submitted in writing for the hearing record. Anyone unable to attend may submit comments in writing to the address above. Written comments must be received by 5:00 p.m. on April 2, 2007.

Persons needing accommodations for effective participation in the meeting should contact the Air Quality Division at 517-373-7045 one week in advance to request mobility, visual, hearing, or other assistance.

This notice of public hearing is given in accordance with Sections 41 and 42 of Michigan's Administrative Procedures Act, 1969 PA 306, as amended, being Sections 24.241 and 24.242 of the Michigan Compiled Laws. Administration of the rules is by authority conferred on the Director of the DEQ by Sections 5503 and 5512 of Act 451, being Sections 324.5503 and 324.5512 of the Michigan Compiled Laws, and Executive Order 1995-18. These rules will become effective immediately after filing with the Secretary of State.

State Office of Administrative Hearings and Rules
PO Box 30695; 611 W. Ottawa Street
Lansing, MI 48909-8195
Phone (517) 335-2484 FAX (517) 335-6696

REGULATORY IMPACT STATEMENT

The department/agency responsible for promulgating the administrative rules must complete and submit this form electronically to the State Office of Administrative Hearings and Rules no less than (28) days before the public hearing [MCL 24.245(3)-(4)]. Submissions may be made to **soahr_rules@michigan.gov**. The SOAHR will review the regulatory impact statement and send its response to the agency (see last page).

A. GENERAL

1. SOAHR #, title, and rule numbers (or rule set range of numbers):

2005-37EQ; Part 8, Emission Limitations and Prohibitions—Oxides of Nitrogen; R 336.1802a to R 336.1816 (Rules 802a to 816) and R 336.1821 to R 336.1834 (Rules 821 to 834).

2. Identify the relationship of the rule to state and federal statutes and regulations:

These rules are being amended as authorized by Sections 5503 and 5512 of Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (Act 451). These rules are being developed to meet requirements of the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rules (CAIR) to reduce transported emissions of oxides of nitrogen (NOx) from electric generating units (EGUs) and large non-electric generating units (non-EGUs). These rules will become part of the Michigan State Implementation Plan (SIP) upon final promulgation.

3. Identify how the rule compares to an industry standard set by a state or national licensing organization.

These rules are patterned after a federal model rule for EPA's CAIR regulations. Similar rules are required in 25 eastern states and the District of Columbia.

4. Is the rule more restrictive or less restrictive than the federal rule or industry standard?

The rules are patterned after a federal model rule and are equivalent to those requirements.

5. What are the sanctions on the state if the rule is not adopted?

The EPA will impose the federal regulation and federal enforcement of the regulation on subject NOx sources in the state.

B. GOAL OF RULE:

6. Identify the conduct and its frequency of occurrence that the rule is designed to change:

The rules will result in reducing NOx emissions from EGUs and non-EGUs, which will help reduce the formation of particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) and ground-level ozone (O_3) in Michigan and downwind areas.

7. Identify the harm resulting from the conduct the rule is designed to change and the likelihood it will continue to occur if the rule is not changed:

If the rules are not promulgated, the EPA will impose a federal rule which will result in NOx reductions, and sanctions may be imposed until state rules are developed such that applicability of the federal rules in Michigan is unnecessary.

8. Estimate the change in the frequency of the targeted conduct expected from the rule change:

The proposed rules will reduce regional NOx emissions by 1.7 million tons per year from the 25 eastern states and the District of Columbia, which will result in reduced levels of $PM_{2.5}$ and O_3 concentrations in Michigan and neighboring areas.

9. Identify any alternatives to regulation by rule that would achieve the same or similar goals:

The provisions could be adopted in legislation instead of through rulemaking. The EPA will impose the federal requirements on the state if the state does not promulgate the measures in this proposed rule.

10. Discuss the feasibility of establishing a regulatory scheme within the industry independent of state intervention:

The federal CAIR program requires the state to develop the regulation to reduce NOx emissions. These measures must be directly enforceable by the state in order to win federal approval.

C. COSTS TO GOVERNMENT UNITS:

11. Estimate the cost of rule imposition on the department or agency promulgating the rule, including the costs of equipment, supplies, labor, and increased administrative costs for initial imposition of the rule and any ongoing monitoring:

The rules are expected to result in minimal additional costs to the agency; they will become part of the normal compliance activity of the agency.

12. Estimate the cost of rule imposition on other state or local governmental agencies, including the cost of equipment, supplies, labor, and increased administrative costs, in both the initial imposition of the rule and any ongoing monitoring:

There will be no additional cost to other state or local agencies.

D. COSTS TO REGULATED INDIVIDUALS:

13. Estimate the actual statewide compliance costs of the rule to individuals, including the costs of education, training, application fees, examination fees, license fees, new equipment or increased labor, exclusive of those costs identified in section C above:

These rules do not apply to individuals.

14. Identify any compliance costs requiring reports and the estimated cost of their preparation by individuals who would be required to comply with the rule:

These rules do not apply to individuals.

15. Estimate the cost of any legal, consulting, and accounting services and any other administrative expenses individuals will incur in complying with the rule:

These rules do not apply to individuals.

16. Estimate the number of individuals the rule affects:

These rules do not apply to individuals.

17. Will the rule have a disproportionate impact on individuals based on their geographic location?

These rules do not apply to individuals.

E. COSTS TO BUSINESSES:

18. Estimate the actual statewide compliance costs of the rule to specifically include small businesses, including the costs of equipment, supplies, labor, training, application fees, permit fees, supervisory costs, exclusive of those identified in sections C and D above:

The costs to EGUs and non-EGUs, including small businesses, as estimated by EPA for all the sources within the 25-state CAIR region, will be approximately $2.4 billion in 2009 and $3.6 billion in 2015 (1999$) for NOx reductions of 1.7 million tons in 2009 and 2 million tons in 2015. This is approximately $1,600 per ton of NOx reduction. For all Michigan sources, this is approximately $260,000 for NOx reductions.

19. Identify any reports the rule requires and the estimated cost of their preparation by businesses; specifically include small businesses:

The rules will not result in any additional costs for reports.

20. Estimate the cost of any legal, consulting, and accounting services and any other administrative expenses businesses will incur in complying with the rule; specifically include small businesses:

There will be no additional costs.

21. Estimate the number of businesses the rule affects:

These rules affect 145 EGUs at 22 stationary sources and 18 non-EGUs at 9 stationary sources.

22. Identify any disproportionate impact the rule may have on small businesses because of their size or geographic location:

Allowing the non-electric generating units to participate in the regional trading program decreases the likelihood of increased regulatory burdens through the purchase of allowances from a broader market place rather than installing costly controls.

23. Discuss the ability of small businesses to absorb the costs estimated above without suffering economic harm and without adversely affecting competition in the marketplace:

The provisions in the hardship allocation set-asides should allow small businesses to absorb the costs without suffering economic harm or affecting competition in the larger electricity supplying market.

24. Estimate the cost of the agency enforcing or administering the rule to exempt or set lesser standards for small businesses:

The cost to affected sources is considered reasonable, and it is not apparent that small businesses should be exempted.

25. Determine the impact on the public interest of exempting or setting lesser standards for small businesses:

The impact to affected sources is considered reasonable, and it is not apparent that small businesses should be exempted.

26. Explain how the agency reduced the economic impact of the rule on small businesses, as MCL 24.240 requires, or discuss why such a reduction was not feasible:

The Department of Environmental Quality (DEQ) included a provision within the rules to allocate extra allowances to the smaller sources, addressing potential inequities in implementation of the requirements.

27. Discuss whether and how the agency has involved both industry and small business in the development of the rule:

The DEQ has a workgroup that includes representatives of industry as well as various associations that represent the industry, both large and small businesses, institutional entities, and environmental organizations.

F. BENEFITS OF RULE:

28. Estimate the primary and direct benefits of the rule, including but not limited to the rule's impact on business competitiveness, the environment, worker safety, and consumer protection.

The rule will reduce emissions of NOx, a precursor to the formation of $PM_{2.5}$ and O_3, and will likely result in lower levels of these pollutants in Michigan, neighboring states, and

Canada. Reduced pollutant levels will have a positive impact on the environment and people in the affected areas.

29. Estimate the secondary or indirect benefits of the rule, including spin-off benefits to business, the environment, workers, and consumers:

Michigan will benefit in having a rule developed with the input of stakeholders instead of a federally imposed rule. Adoption of the state rule avoids imposition of a federal rule pursuant to 40 C.F.R. Part 97.

30. Are the direct and indirect benefits of the rule likely to justify the cost?

A better environment resulting in better health and productivity for individuals justifies the reasonable costs involved in implementing this rule. The EPA estimates that the regionwide implementation of the CAIR requirements will result in savings of $100 billion dollars in annual health costs. The EPA has mandated these requirements and believes that the benefits justify the costs in terms of cleaner air and human health standards.

31. Estimate the cost reductions to government, individuals, and businesses as a result of the rule:

There are no expected cost reductions to government, individuals, or businesses as a result of this rule.

32. Estimate the increased revenues to state or local government units as a result of the rule:

No revenue increase is expected.

33. Identify the sources you relied upon in calculating your cost and benefit responses:

The responses were based on information provided by the EPA's Office of Air and Radiation, Clean Air Markets Division, and the DEQ Air Quality Division staff's familiarity with regulatory costs and impacts.

Reviewed by SOAHR Representative:

Norene Lind, Administrative Rules Manager

SOAHR Response:

Date received: 11-22-06		
Approval	**X**	
Disapproval		Explain:
More information needed		Explain:
Date: 11-22-06		SOAHR #: 2005-037EQ

ATTACHMENT F

Public Hearing Record

STATE OF MICHIGAN

DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR QUALITY DIVISION

PROPOSED RULE REVISIONS

SOAHR 2005-037EQ

PART 8.
Emission Limitation and Prohibitions—Oxides of Nitrogen

R 336.1802a, R 336.1803, R 336.1821 to R 336.1826, and
R 336.1830 to R 336.1834

April 2, 2007
Lansing, Michigan

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STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENTAL QUALITY
LANSING

JENNIFER M. GRANHOLM
GOVERNOR

STEVEN E. CHESTER
DIRECTOR

NOTICE OF PUBLIC HEARING
DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

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G. Vinson Hellwig, Chief
Air Quality Division

Department of Environmental Quality

Opening Statement
By: Marion Hart, Hearings Officer

April 2, 2007

Introduction

Good afternoon ladies and gentlemen. My name is Marion Hart, and I am the Supervisor of the Administration Section in the Air Quality Division of the Michigan Department of Environmental Quality. I will be serving as the Hearing Officer for this public hearing on the revision of Part 8 of the Air Pollution Control Rules.

With me today are other DEQ staff who will be assisting with this hearing. Seated with me are Teresa Walker, of the Strategy Development Unit, who prepared the rule revisions, and Vince Hellwig, Chief of the Air Quality Division, who is representing the Director of the Department of Environmental Quality, the decision-maker on administrative rules.

Background Information

By way of background information, the Air Quality Division is responsible for protecting Michigan's air resources. The law governing those responsibilities is Sections 5503 and 5512 of Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended.. We are here today for a public hearing on amendments to Parts 8 to the administrative rules for Air Pollution Control, State Office of Administrative Hearings and Rules No. 2005-037EQ.

I will now ask Teresa Walker to briefly summarize the proposed revisions.

Purpose of Public Hearing

In order for rule promulgation to occur, the DEQ must follow the procedures set forth in the Administration Procedures Act of 1969 and the State Office of Administrative Hearings and Rule's procedures.

The purpose of today's hearing is to give anyone interested in the proposed rules an opportunity to provide information that the DEQ can use in making the decision.

Procedures

Notice of this hearing was published in the Oakland Press, Grand Rapids Press, Lansing State Journal, and Marquette Mining Journal on February 23, 2007. The notice and proposed rules were also published in the Michigan Register on March 1, 2007. Copies of the hearing notice, Regulatory Impact Statement, proposed rules, and summary of the proposed rules were made available to those interested and are available here today.

As you came today, you were given an opportunity to fill out a public comment card. We request that everybody fill out a card and indicate if you wish to make comments. We will use these cards to maintain a record of people interested in the proposed rules and to call upon those who want to make a statement today. To ensure that the hearing is conducted in a fair manner, we will follow these steps:

1. I will call on those who have indicated on the cards that they would like to speak in the general order in which the cards were turned in. When all the cards have been completed, I will ask if anyone else would like to make a statement.

2. When your name is called, please come to the microphone, face me, and make your statement. If you have written comments or materials you would like to present, please hand them to me as you come to the microphone. As you begin your comments, please state your name and any group or association you may represent.

How the Information Will be Used

This hearing is being recorded and your comments will be a part of the information the DEQ will consider in making its decision on the proposed rules. The public comment period for the proposed rules ends today at 5:00 p.m.

Following the public hearing, the DEQ staff will review all comments and prepare an Agency Report, which includes the response to comments. The Agency Report will be available on the DEQ website or by contacting the Air Quality Division office. The proposed rules and the Agency Report will be submitted to the State Office of Administrative Hearings and Rules and the Joint Committee on Administrative Rules. Following JCAR, the rules will be filed with the Secretary of State and become effective immediately. It is estimated this process will take approximately four to five months.

Thank you for your attention. I will now begin calling the names of those who have indicated they would like to make a statement.

Closing Statement

Thank you for your comments and cooperation today. We appreciate your interest in these proposed rules and that you took the time to be here.

As indicated at the beginning of the hearing, the closing date of the public comment period is today at 5:00 p.m. and an Agency Report will be prepared.

The hearing is now closed. Thank you again.

STAFF STATEMENT

AIR QUALITY DIVISION
DEPARTMENT OF ENVIRONMENTAL QUALITY

By: Teresa Walker, Strategy Development Unit

April 2, 2007

SUBJECT: Proposed administrative rules R 336.1802a, R 336.1803, R 336.1821 to R 336.1826, and R 336.1830 to R 336.1834.

PRINCIPAL REASONS FOR THE PROPOSED RULES

These rules are being developed to meet requirements of the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR) to reduce transported emissions of oxides of nitrogen (NOx) from electric generating units (EGUs) and large non-electric generating units. The rules will be submitted to the EPA as part of the Michigan State Implementation Plan (SIP) upon final promulgation.

The federal CAIR program requires the state to develop the regulations to reduce NOx emissions. The proposed rules will result in reduced NOx emissions from EGUs and large non-EGUs, which will help reduce the formation of particulate matter less than 2.5 microns in diameter and ground-level ozone in Michigan and downwind areas. The Department of Environmental Quality (DEQ) worked with a number of stakeholders to develop and adopt these rules. The workgroup included representatives from various industrial, commercial, small business, consumer and environmental groups, and associations. The workgroup met several times during 2005 and 2006.

SUMMARY OF THE CONTENTS OF THE PROPOSED RULES

Rules 802a, 803, 821 through 826, and 830 through 834 are based on the EPA CAIR rules, a NOx emissions cap and trade system to be administered by the EPA.

- Rule 802a contains language adopting specific provisions of 40 CFR Parts 72, 75 and 97 by reference, pursuant to the federal CAIR program requirements.
- Revisions to Rule 803 modify the existing definitions to address the CAIR requirements.
- Rule 821 contains applicability criteria.
- Rule 822 establishes the NOx budgets for the ozone season control period and establishes the allocation methodology procedures for the ozone season. See the attached spreadsheets for the allocation tables for each group.
- Rule 823 establishes the provisions for a new source set-aside ozone season control period allocation pool for new EGUs, new non-EGUS, and newly affected EGUS (which were not included in the original NOx program due to geographic location).

- Rule 824 establishes the provisions for a hardship set-aside ozone season control period allocation pool to address issues for small businesses that are impacted by the rules.
- Rule 825 establishes the provisions for a renewable set-aside ozone season control period allocation pool to encourage the use of renewable energy in the production of electricity in the state.
- Rule 826 adopts by reference the ozone season control period opt-in provisions under the federal CAIR rules.
- Rule 830 establishes the NOx budgets for the annual control period and establishes the allocation methodology procedures for the annual control period. See the attached spreadsheets for the allocation tables for each group.
- Rule 831 establishes the provisions for a new source set-aside annual control period allocation pool for new EGUs.
- Rule 832 establishes the provisions for a hardship set-aside annual control period allocation pool to address issues for small businesses that are impacted by the rules.
- Rule 833 establishes the provisions for an annual control period compliance supplement pool with early reduction credit generation and hardship provisions for the newly affected EGUs that were not in the original NOx Budget Program and are adversely impacted by this new program for 2009.
- Rule 834 adopts by reference the opt-in provisions for the annual control period under the federal CAIR rules.

Allocation spreadsheets are also being made part of this public hearing and will become part of the SIP Submittal. Due to comments from the affected facilities, the allocation spreadsheets have been modified from the originals sent out. These updates include corrections to heat input values and fuel type factors. The corrected sheets were made available to the members of the workgroup on Friday March 30, 2007, and copies are available here.

That concludes my statements on the proposed rule revisions.

Consumers Energy

A CMS Energy Company

Environmental & Laboratory Services

Ms. Teresa Walker
Air Quality Division
Michigan Department of Environmental Quality
P.O. Box 30260
Lansing, Michigan 48909-7760

SUBJECT: State of Michigan's Proposed Rules to Implement the Federal Clean Air Interstate Rule – SOAHR 2005-037EQ

Ms. Walker:

This letter transmits a copy of comments prepared by Consumers Energy, regarding the Department of Environmental Quality's proposed rules to implement the Federal Clean Air Interstate Rule. Consumers Energy was an active participant in the workgroup charged with the development of this rules package. We are appreciative of the efforts by the staff of the Air Quality Division in working on these rules.

Consumers Energy is largely supportive of these proposed rules. While we are in agreement with the approach taken, we do have a substantial list of comments that are editorial in nature. Those comments are attached.

We thank the DEQ for this opportunity to comment. If there are any questions, please direct them to Jason Prentice, at 517-788-1467, or to me.

Sincerely,

AKEvans, Director of Air Quality
Environmental & Laboratory Services Dept.
Consumers Energy
1945 W. Parnall Road
Jackson, MI 49201

1945 W. Parnall Road • Jackson, MI 49201 • Fax: 517 788 2329 • www.consumersenergy.com

All of the following comments are intended to be consistent with our understanding of workgroup discussions and to help clarify rule applicability. They are presented in the sequential order in which the proposed rules are written. Text proposed to be added is shown in ***bold italic underline***. Text proposed to be deleted is shown in ~~strikethrough~~.

Rule 802a

No comments.

Rule 803

803(3)(d)

(d) "~~EGU" means e~~***E***lectric generating unit ***(EGU)", for the purposes of R336.1821 to R 336.1834, means any stationary fossil fuel-fired boiler or stationary fossil fuel-fired combustion turbine that is located in Michigan and is defined as a CAIR NOx unit and a CAIR NOx ozone season unit under 40 C.F.R. § 97.104 and § 97.304, respectively.***

Comment: Throughout R 336.1821 to R 336.1834, the term "EGU" is essentially used to describe affected units under CAIR that are located within Michigan. Rather than introducing the additional term "Michigan EGUs", the definition of EGU should simply include the concept that the unit must be located within Michigan. Furthermore, the term "Michigan EGU" does not accurately reflect affected units under CAIR because it does not include the concept of cogeneration or solid waste incineration units. Such units may serve a generator with a nameplate capacity of more than 25 megawatts, but they may still be exempt from CAIR and should therefore not be classified as EGUs under R 336.1821 to R 336.1834. With the proposed change to R 336.1803(d), the term "Michigan EGU" in R 336.1803(h) is no longer needed and should be removed. Please note that the remainder of the comments are based upon the current rule numbering and do not reflect the proposed deletion of R 336.1803(h).

803(3)(j)

(j) "~~Michigan n~~***N***on-EGUs" means the following ***units located within Michigan***:
(i) For units that commenced operation before January 1, 1997, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1995 or 1996 a generator producing electricity for sale.
(ii) For units that commenced operation on or after January 1, 1997, and before January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1997 or 1998 a generator producing electricity for sale.
(iii) For units that commence operation on or after January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and to which either of the following provisions applies:

(A) The unit at no time serves a generator producing electricity for sale.
(B) The unit at any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of 25 megawatts or less and has the potential to use not more than 50% of the potential electrical output capacity of the unit.
(iv) Any other unit that was subject to Michigan's NOx Budget Trading Program as of December 31, 2008, but is not defined as an EGU under R 336.1803(d).

> *Comment:* The definition of non-EGU should inherently include the concept that any such source must be located within Michigan. Further, this is more consistent with how the term "non-EGU" is used throughout R 336.1821 to R 336.1834. The definition of EGU for purposes of the NOx Budget Trading Program and the CAIR program are different, and units that were classified as EGUs under the NOx Budget Trading Program may not be classified as EGUs under the CAIR program. With the CAIR NOx program essentially replacing the NOx Budget Trading Program, any such units should be re-classified as non-EGUs.

803(3)(n)

(n) "Renewable energy source," for allocation purposes under R 336.1821 to R 336.18***26***~~3~~4, means a source ***located within Michigan*** that generates electricity by solar, wind, geothermal, or hydroelectric processes, excluding nuclear, that has commenced operation or is projected to commence operation on or after January 1 of the most recent year of the 5-year period used to calculate the allocations pursuant to these rules, which meets all of the following: ...

> *Comment:* Qualifying renewable energy projects would receive allocations from the CAIR NOx ozone season program. Therefore, R 336.1830 to R 336.1834 should not be referenced, as these rules pertain to the CAIR NOx annual program. For purposes of clarification, the definition of "renewable energy source" should specify that the renewable energy source must be located within Michigan to be eligible to receive allocations.

803(3)(o)

(o) "Renewable energy projects," for allocation purposes under R 336.1821 to R 336.18***26***~~3~~4, means renewable energy sources located within the same geographic area ***of Michigan and supplying a single common substation or single transmission system interconnect,*** that when added together equal a generator greater than 25 megawatts of electrical output.

> *Comment:* Again, R 336.1830 to R 336.1834 should not be referenced, as these rules pertain to the CAIR NOx annual program. It must be specified that the renewable energy projects to be aggregated are all located in Michigan, and to constitute a "project" each source should be aggregated into the electric transmission system at a single common point of transfer. The term "same

geographic area" is so broad as to be essentially meaningless unless it is further qualified.

<u>Rule 821</u>

821(1)(b)

(b) ~~Ozone season~~ CAIR NOx ***<u>ozone season</u>*** units as defined pursuant to 40 C.F.R part 97 and all units required to be in the state's NOx SIP call trading program that are not already included under 40 C.F.R. §9<u>7</u>~~6~~.304 and are defined in R 336.1803(3)~~(h) and~~ (j).

> *Comment:* For purposes of consistency with 40 C.F.R. part 97, the term "ozone season CAIR NOx unit" should be replaced with the term "CAIR NOx ozone season unit", consistent with the definition in § 97.302. Further, Michigan is adopting the CAIR applicability provisions as contained in the federal implementation plan (FIP), and the reference to § 96.304 should accordingly be changed to § 97.304. Lastly, EGUs would be included under §97.304, and the rule citation should be changed to R 336.1803(j).

821(1)(c)

(c) For purposes of allocating allowances under R 336.1821 to R 336.18***<u>26</u>***~~34~~, the following units which are not addressed in subparagraphs (a) and (b) of this subrule are CAIR NOx ***<u>ozone season</u>*** units:
(i) Renewable energy sources
(ii) Renewable ***<u>energy</u>*** ~~source~~ projects

> *Comment:* Per preceding comments, the rule references and CAIR NOx unit terminology should be revised. Also, the term "renewable source projects" is not defined in R 336.1803 and should be changed to renewable energy projects, consistent with R 336.1803(o). More fundamentally, is it even necessary to state that renewable energy sources and renewable energy projects are CAIR NOx ozone season units? It seems as though actually treating these sources as CAIR NOx units could be somewhat problematic, as CAIR NOx ozone season units are required to have permits, designated representatives, etc. It seems as though the owner or operator of a renewable energy source would simply establish a general account for purposes of receiving allocations under R 336.1821 to R 336.1826.

821(3)

(3) After January 1, 2008, any ~~Michigan~~ EGU ***<u>as defined in R 336.1803(d)</u>*** that does not utilize fossil fuels of any kind for the production of electricity is determined to be exempt from R 336.1802a to R 336.1834.

> *Comment:* With the proposed deletion of the term "Michigan EGU", R 336.1821(3) must be revised in order to reference the definition of EGU for the CAIR NOx program.

821(4)

(4) The fuel type adjusted allocations for each ***existing*** EGU shall be determined by multiplying the ***appropriate NOx emission rate and heat input, as determined in accordance with R 336.1822 and 336.1830, with an*** appropriate coefficient ***("fuel adjustment factor, or FAF")*** as follows:
(a) For a solid fuel-fired EGU ~~or cogeneration unit~~, the allocation calculations shall be adjusted by multiplying ~~the allocation values~~ by 100% ***(i.e. 1.0)***.
(b) For a liquid fuel-fired EGU ~~or cogeneration unit~~, the allocation calculations shall be adjusted by multiplying ~~the allocation values~~ by 60% ***(i.e. 0.6)***.
(c) For a gaseous fuel-fired EGU ~~or cogeneration unit~~, the allocation calculations shall be adjusted by multiplying ~~the allocation values~~ by 40% ***(i.e. 0.4)***.
(d) For a multi-fueled EGU, the allocation adjustment ~~calculation~~ shall ~~be~~ ***use*** a weighted ***coefficient*** based on the percentage heat input from each type of fuel burned in the unit ***during the two year period consistent with the heat input value determined in accordance with R 336.1822(6) or 336.1830(4), as appropriate***, unless the source can demonstrate that certain types of fuel used in the process provided less than 10% of the annual heat input ***during such time period***. If so, then the allocation adjustment ***coefficient*** is calculated based on only those fuel types which contributed 10% or more of the annual heat input ***during the two year time period***.

> *Comment:* Subsequent rules refer to "fuel adjustment factors", but the term is not currently defined in R 336.1803 to R 336.1834. The proposed language is intended to clarify that the "fuel adjustment factors" are consistent with the coefficients specified in R 336.1821(4). Furthermore, for multi-fueled EGUs, the heat input weighted FAF should be consistent with the two year period used to derive the heat input in accordance with R 336.1822(6) or 336.1830(4). The proposed revisions are designed to clarify the application of the FAFs and the derivation of the FAFs for multi-fueled units.

821(5)(b)

(b) A unit's total tons of oxides of nitrogen emissions during specified calendar years ***or ozone seasons*** as determined under 40 C.F.R. part 75, adopted by reference in R 336.1802***a***.

> *Comment:* R 336.1821(5)(a) refers to both annual and ozone season heat input rates or megawatt energy produced, and R 336.1821(5)(b) should also reference both annual and ozone season time periods. Further, R 336.1802 is not applicable after January 1, 2009 and should be replaced with a reference to R 336.1802a.

Rule 822

822(1)

Rule 822. (1) The CAIR NOx ozone season trading program budget allocated by the department under subrule (3) of this rule for the CAIR NOx ozone season control periods to the EGUs, non-EGUs, and renewable ***energy sources*** ~~units~~ shall ***annually*** equal the total number of tons of oxides of nitrogen emissions as indicated in the following manner:

> *Comment:* The term "renewable units" is not defined and should be replaced with "renewable energy sources" consistent with R 336.1803(3)(n). Further, the budget amounts described in the rest of this subrule apply to the ozone control period in each calendar year (i.e. the budget amounts are not totals for the time periods 2010-2011, 2012-2014, etc.). The proposed language is intended to clarify that the budget amounts apply to each calendar year within the designated time frames.

822(4)(a)(i)

(i) During calendar years 2010 to 2014 as follows:
(A) Units with an allowable ***NOx*** emission rate equal to or greater than the CAIR target budget rate of 0.15 pounds per million Btu***, and units with no applicable NOx emission rate,*** shall receive ***an initial unadjusted allocation of*** allowances in an amount equaling 0.15 pounds per million Btu multiplied by the appropriate fuel adjustment factor and ~~multiplied by~~ the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.
(B) Units with an allowable ***NOx*** emission rate less than the CAIR target budget rate of 0.15 pounds per million Btu shall receive ***an initial unadjusted allocation of*** allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate***:***~~.~~

[equation not shown]

Where:

Allocation =	The ***initial*** unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 20***10***~~09~~ to 2014 ***(0.15 lb/mmBtu)***.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate ***(lb/mmBtu)***.
HI =	***Heat input as determined in accordance with subrule (6)*** ~~Average of the unit's 2 highest heat~~

~~inputs for the appropriate 5 control periods~~ ***(mmBtu)***.

Comment: The "units with no applicable NO_X emission rate" language in (4)(a)(i)(A) is intended to clarify coverage for any so-called "grandfathered" unit whose installation may have pre-dated any NO_X emission limit.

The "initial unadjusted allocation of" language is intended to clarify that the units will not necessarily receive the allowances calculated according to the formula (as written, the "units…shall receive allowances"). The initial allocation may later be adjusted in subrule (5).

The changes in the table following the equation are intended to clarify what units the various terms are expressed in, the time period for the CAIR target emission rate, and the appropriate heat input value to be used in the calculation.

822(4)(a)(ii)

(ii) During calendar years 2015 and thereafter as follows:
(A) Units with an allowable ***NOx*** emission rate equal to or greater than the CAIR target budget rate of 0.125 pounds per million Btu***, and units with no applicable NOx emission rate,*** shall receive ***an initial unadjusted allocation of*** allowances in an amount equaling 0.125 pounds per million Btu multiplied by the appropriate fuel adjustment factor and ~~multiplied by~~ the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.
(B) Units with an allowable ***NOx*** emission rate less than the CAIR target budget rate of 0.125 pounds per million Btu shall receive ***an initial unadjusted allocation of*** allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate***.***~~:~~

[equation not shown]

Where:	
Allocation =	The ***initial*** unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2015 and thereafter ***(0.125 lb/mmBtu)***.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate ***(lb/mmBtu)***.
HI =	***Heat input as determined in accordance with subrule (6)*** ~~Average of the unit's 2 highest heat inputs for the appropriate 5 control periods~~ ***(mmBtu)***.

Comment: These changes are identical to those in 822(4)(a)(i), except for using the appropriate "2015 and thereafter" target emission rate.

822(6)

(6) The heat input, in million Btu's, used for calculating oxides of nitrogen allowance allocations for each subject unit under this rule shall be the unit's average of the 2 highest heat inputs for the ozone season control period in the 5 years immediately preceding the year in which the department is required to submit the oxide of nitrogen allocations. ***Notwithstanding the preceding, multi-fueled EGUs may choose to average any two (2) of the ozone season control period heat inputs in the 5 years immediately preceding the year in which the department is required to submit the oxide of nitrogen allocations.*** If the unit operated less than 2 full ozone seasons of the 5-year time period, then the unit's single highest heat input shall be used.

Comment: For multi-fueled EGUs, the two highest ozone season heat inputs may not correspond to the highest adjusted heat inputs when considering the weighted FAFs. Therefore, such units should be allowed to use any two (2) of the ozone control period heat inputs within the appropriate five year period in order to determine the heat input used for allocations.

Rule 823

823(2)(a)

(a) The oxides of nitrogen allowance allocation request shall be submitted before March 1***,*** ~~of the~~ 2009 ~~ozone season control period~~.

Comment: The current wording references March 1 of the 2009 ozone control period (which does not start until May 1, 2009). This rule should be revised to simply reference March 1, 2009.

823(2)(b)

(b) The CAIR authorized account representative of any newly-affected EGU may request 2009 CAIR NOx ozone season allowances, based on an amount equaling 0.15 pounds per million Btu multiplied by the unit's ***appropriate fuel adjustment factor as defined in R336.1821 and the unit's*** ozone season heat input ***as determined in accordance with R 336.1822(6)***, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

> *Comment:* The fuel adjustment factor was left out of this calculation. Furthermore, the heat input rate used for this allocation should be consistent with the heat input rate used for allocations under Rule 822. With the proposed revisions to Rule 823(3)(b), Rule 823(3)(c) should be deleted.

823(3)(a) and (b)

(a) The CAIR NOx ozone season allowance allocation request shall be submitted before March 1 of the year of the first ozone control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the ***non-EGU*** ~~oxides of nitrogen unit~~, if required, and each following year by March 1.
(b) The CAIR authorized account representative of any new non-EGU may request CAIR NOx ozone season allowances, based on an amount equaling 0.17 pounds per million Btu or the allowable emission rate, whichever is more stringent, multiplied by the ***heat input rate determined in accordance with subrule (3)(b)(i) or (ii)*** ~~the maximum design heat input or the permit allowable heat input, whichever is more stringent, in million Btu's per hour~~, divided by 2,000 pounds per ton and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.
(i) For the first ozone season for which each new non-EGU requests allowances, the heat input rate shall be determined as follows:

$$Estimated\ Heat\ Input = Rated\ Heat\ Input \times Hours\ of\ operation \times 70\%$$

Where:

Estimated Heat Input	=	***Estimated heat input rate, in mmBtu, during the first ozone control period.***
Rated Heat Input	=	***The maximum design heat input or the permit allowable heat input, whichever is more stringent, in mmBtu/hour.***
Hours of operation	=	***Predicted hours of operation for the control period.***

(ii) For each consecutive ozone season for which each new non-EGU requests allowances, the heat input rate shall be based upon the actual heat input rate during the control period immediately preceding the request.

(c) When the new non-EGU has been placed in the existing pool, the calculation methods under R 336.1822 apply.

Comment: The term "oxides of nitrogen unit" is not defined and should be replaced with the term "non-EGU".

The allocation formula for new non-EGUs is incorrect, as the final units of the multiplication approach would be "ton/hour", not tons per control period. The allocation has to be based upon the heat input during the ozone season control period. Unfortunately, there are no provisions for determining the appropriate ozone season heat input during the first year that allocations are requested or any of the subsequent years (before the unit becomes an existing unit). The proposed language mirrors the new unit allocation approach for EGUs and is designed to provide clarification.

Lastly, a provision should be added to address the fact that the allocation procedures of R 336.1822 apply once the new non-EGU becomes an existing unit.

823(4)(a) and (b)

(a) The CAIR NOx ozone season allowance allocation request shall be submitted before March 1 of the year of the first ozone control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the ~~oxides of nitrogen unit~~ ***EGU***, if required, and each following year by March 1.
(b) The allocation methodology used for the first ozone season for which each new EGU requests allowances shall be calculated using the following formula:

[equation not shown]

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on ***gross*** electric generation.
Size of the unit =	The maximum design capacity of the EGU in ***gross*** megawatts.
Hours of Operation =	Predicted hours of operation per control period.
MWh =	Megawatt hours.

(c) The allocation methodology used for each consecutive ozone season for which each new EGU requests allowances shall be calculated using the following formula:

[equation not shown]

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on ***gross*** electric generation.

Actual megawatt hours =	The actual ***gross*** megawatt hours of electricity generated during the control period immediately preceding the request.
MWh =	Megawatt hours.

Comment: The term "oxides of nitrogen unit" is not defined and should be replaced with the term "EGU". In both of the allocation equations, the NOx allocation factor must be specified on a gross or net basis. We suggest that gross electrical output be used for allocation purposes. This is consistent with the output based NOx emission limit in 40 C.F.R. part 60, Subpart Da. Furthermore, units that use all of their heat input for electrical generation are required to monitor, record and report gross electrical output pursuant to 40 C.F.R. part 75.

General Comment – 40 CFR 60, Subpart Da indicates that an output based limit of 1.0 lb/MWh is approximately equivalent to an input based limit of 0.11 lb/mmBtu. It is possible that a new unit will have a NOx emission limitation of less than 1.0 lb/MWh due to BACT, LAER, etc. Should the allocation factor for new units be the more stringent of 1.0 lb/MWh or the permitted emission limit, the average of 1.0 lb/MWh and the emission limit (similar to the allocation concept for existing units), or some other method?

823(5)

(6) CAIR NOx ozone season allowances not allocated or requested that remain in the new source set-aside pool for any allocation year shall be re-allocated to the existing EGU and non-EGU source pools~~, using the allocation methodologies as outlined in R 336.1822~~. ***For a given allocation year, re-allocation between the existing EGU and non-EGU pools shall be based upon the associated ratio of the existing EGU and non-EGU pools relative to the total pool for the existing EGUs and non-EGUs, with the re-allocations for each pool rounded to the nearest whole ton.***

Comment: Consumers Energy fully supports the re-allocation of allowances that remain in the new source set-aside pool back to the existing EGU and non-EGU pools. However, there are separate pools for the existing EGUs and non-EGUs, and the relative amount of re-allocations to each of these pools must be defined.

For purposes of re-allocation, Consumers Energy suggests that any remaining allowances be split between the existing EGU and non-EGU pools based upon the relative size of each of these pools for a given compliance period. For example, assume that there were 500 allowances remaining in the 2010 new source set-aside pool. These allowances would be re-allocated back to the existing EGU and non-EGU pools as follows: existing EGU pool = 28,321/(28,321+1,309) * 500 = 477.9 (rounds to 478); existing non-EGU pool = 1,309/(28,321+1,309) * 500 = 22.1 (rounds to 22).

Rule 824

824(2)(c)(i)

(i) Historical heat input utilization levels shall be based on the ***ozone season heat input determined in accordance with R 336.1822(6)***~~unit's average of the 2 highest heat input utilization levels for the ozone season in the 5 years immediately preceding the year in which the department is required to submit the oxides of nitrogen allocations to the U.S. environmental protection agency. If the unit operated less than 2 full ozone seasons during the 5-year time period, then the unit's single highest heat input level shall be used.~~

> *Comment:* The heat input rate used for this allocation should be consistent with the heat input rate used for allocations under Rule 822.

824(3)(a)(i)

(3) The department shall allocate CAIR NOx ozone season hardship allowances to existing CAIR NOx ozone season units which have submitted an engineering analysis as described in the following procedures:
(a) The authorized account representative shall demonstrate to the department that the control level required pursuant to this rule results in excessive or prohibitive cost for compliance. The demonstration shall include all of the following:
(i) An engineering study analyzing all control options that are technically available for the unit, including control options that would achieve a level of control meeting, at a minimum, ***the levels specified in subrules (A), (B) and (C)***~~a 0.15 pound per million Btu emission rate~~. Sources that previously submitted an engineering analysis and received hardship allowances pursuant to R 336.1810(4)(f) for the oxides of nitrogen budget program ***or an alternate NOx emission limitation or standard pursuant to R 336.1801(4)(g)*** may submit written updates to their previous plan.
(A) For EGUs during the time period between 2010 and 2014, a NOx emission rate of 0.15 pound per million Btu.
(B) For EGUs in 2015 and beyond, a NOx emission rate of 0.125 pound per million Btu.
(C) For non-EGUs, a NOx emission rate of 0.17 pound per million Btu.

> *Comment:* In regards to the hardship allowances, the target NOx emission rate should be consistent with the NOx emission rate used for allocation purposes. In addition, units subject to R 336.1801(4)(g) were required to submit an engineering analysis very similar to that required under R 336.1810(4)(f). Therefore, engineering analyses submitted for purposes of R 336.1801(4)(g) should also be eligible for use under R 336.1824(3)(a)(i).

Rule 825

825(2)

(2) ***The owner(s) or operator(s)*** ~~An authorized account representative~~ of a renewable energy source or renewable energy project, as defined under R 336.1803, may request a CAIR NOx ozone season allowance allocation under this rule.

> *Comment:* Renewable energy sources and renewable energy projects are not affected units under the federal CAIR program. Therefore, such units will not have compliance accounts. While the owners and operators of such units could establish general accounts for the purpose of receiving allowance allocations, the general accounts would not be tied back to the associated units. Thus, a renewable energy source or a renewable energy project will not have an authorized account representative.

825(3)(a)

(a) The oxides of nitrogen allowance allocation request shall be submitted before March 1 of the year of the first ozone control period for which the oxides of nitrogen allowance allocation is requested ~~and after the date on which the department issues a permit to install for the unit, if required,~~ and each following year by March 1.

> *Comment:* By definition, renewable energy sources and renewable energy projects are non-emitting. Therefore, it does not seem necessary to mention a permit to install, which would not apply to non-emitting sources.

825(3)(b)

(b) The allocation methodology used for ***each*** ~~the first~~ ozone season for which each renewable energy source or renewable energy project requests allowances shall be calculated using the following formula:

[equation not shown] – Delete equation and replace with:

$$Allocation = \frac{1.0\ lb\ NOx}{MWh} \times \frac{Actual\ Megawatt\ hours}{2000\ lb/ton}$$

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on ***gross*** electric generation.
~~Size of the unit~~***Actual megawatt hours =***	The ~~maximum design capacity of the renewable energy source or project~~***actual gross megawatt hours of electricity generated during the control period immediately preceding the request.***
~~Hours of Operation =~~	~~Predicted hours of operation per control period.~~

MWh = Megawatt hours.

Comment: EGUs and non-EGUs must have allowances for purposes of compliance (starting with initial operation), and these allowances represent an immediate operating cost. In contrast, renewable energy sources and projects are non-emitting sources that do not need allowances to cover their operation. Due to this basic difference, it is not necessary to award allowances to renewable energy sources and projects based upon projected operation. Rather, allowances to these types of sources should always be based upon actual production. Further, we suggest that allowances bet awarded on gross generation (consistent with the proposed allocation method for new EGUs). With the proposed revisions to Rule 825(3)(b), Rule 825(3)(c) should be deleted.

825(4) and (5)

(4) The renewable energy source or renewable energy project's eligibility ***for*** ~~to request~~ allowances shall begin not sooner than the calendar year 2005.
(5) ~~The authorized account representative of a~~ ***An individual*** renewable energy source ***(alone or as part of a*** ~~or~~ renewable energy project***)*** may only ***receive*** ~~request~~ allowances for 3 consecutive ozone seasons.

Comment: It is the owner(s) or operator(s) of the renewable energy source or project who would request allowances, not the actual units or group of units. Furthermore, an individual renewable energy source or project will not have an authorized account representative, as the unit or groups of units would not be an affected source under the federal CAIR program. Lastly, it is each physical renewable energy source or project which should only be eligible to receive allocations for 3 consecutive ozone seasons, not the owner(s) or operator(s) of such sources.

825(6)

(6) CAIR NOx ozone season allowances not allocated or requested that remain in the renewable allocation set-aside pool for any allocation year shall be re-allocated to the existing EGU and non-EGU source pools~~, using the allocation methodologies as outlined in Rule 822~~. ***For a given allocation year, re-allocation between the existing EGU and non-EGU pools shall be based upon the associated ratio of the existing EGU and non-EGU pools relative to the total pool for the existing EGUs and non-EGUs, with the re-allocations for each pool rounded to the nearest whole ton.***

Comment: Again, Consumers Energy fully supports the re-allocation of allowances that remain in the renewable set-aside pool back to the existing EGU and non-EGU pools, but the relative amount of re-allocations to each of these separate pools must be defined. For purposes of re-allocation, Consumers Energy suggests that any remaining allowances be split between the existing EGU and non-EGU pools based upon the relative size of each of these pools for a given compliance period.

Rule 826

No comments.

Rule 830

830(3)(a)

(a) During calendar years 20***09***~~10~~ to 2014:

> *Comment:* Allowances for the CAIR NOx annual control period must be distributed starting in 2009, not 2010.

830(3)(a)

(3) For the CAIR NOx annual control periods under subrules (1)(a) and (b) of this rule, the department shall allocate allowances to existing EGU units that commenced operation before January 1 of the most recent year of the 5-year period used to calculate heat input. The department shall allocate the following allowances to each existing CAIR NOx unit:
(a) During calendar years 20***09***~~10~~ to 2014:
(i) Units with an allowable ***NOx*** emission rate equal to or greater than the CAIR target budget rate of 0.15 pounds per million Btu***, and units with no applicable NOx emission rate,*** shall receive ***an initial unadjusted allocation of*** allowances in an amount equaling 0.15 pounds per million Btu multiplied by the appropriate fuel adjustment factor and ~~multiplied by~~ the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.
(ii) Units with an allowable ***NOx*** emission rate less than the CAIR target budget rate of 0.15 pounds per million Btu shall receive ***an initial unadjusted allocation of*** allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate***:***~~.~~

[equation not shown]

Where:

Allocation =	The ***initial*** unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2009 to 2014 ***(0.15 lb/mmBtu)***.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate ***(lb/mmBtu)***.
HI =	***Heat input as determined in accordance with subrule (4)***~~Average of the unit's 2 highest heat~~

~~inputs for the appropriate 5 control periods~~ ***(mmBtu)***.

Comment: Allowances for the CAIR NOx annual control period must be distributed starting in 2009, not 2010. Other comments, same as for Rule 822(4)(a)(i)...

The "units with no applicable NO_X emission rate" language in (3)(a)(i) is intended to clarify coverage for any so-called "grandfathered" unit whose installation may have pre-dated any NO_X emission limit.

The "initial unadjusted allocation of" language is intended to clarify that the units will not necessarily receive the allowances calculated according to the formula (as written, the "units...shall receive allowances"). The initial allocation may later be modified in subrule (5).

The changes in the table following the equation are intended to clarify what units the various terms are expressed in.

830(3)(b)

(3) For the CAIR NOx annual control periods under subrules (1)(a) and (b) of this rule, the department shall allocate allowances to existing EGU units that commenced operation before January 1 of the most recent year of the 5-year period used to calculate heat input. The department shall allocate the following allowances to each existing CAIR NOx unit:

...

(b) During calendar years 2015 and thereafter the following apply:

(i) Units with an allowable ***NOx*** emission rate equal to or greater than the CAIR target budget rate of 0.125 pounds per million Btu***, and units with no applicable NOx emission rate,*** shall receive ***an initial unadjusted allocation of*** allowances in an amount equaling 0.125 pounds per million Btu multiplied by the appropriate fuel adjustment factor and ~~multiplied by~~ the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(B) Units with an allowable ***NOx*** emission rate less than the CAIR target budget rate of 0.125 pounds per million Btu shall receive ***an initial unadjusted allocation of*** allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate***:***~~.~~

[equation not shown]

Where:

Allocation =	The ***initial*** unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2015 and thereafter ***(0.125 lb/mmBtu)***.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate ***(lb/mmBtu)***.
HI =	***Heat input as determined in accordance with subrule (4)***~~Average of the unit's 2 highest heat inputs for the appropriate 5 control periods~~ ***(mmBtu)***.

Comment: These changes are essentially identical to those in 830(3)(a), except for using the appropriate "2015 and thereafter" target emission rate.

830(4)

(4) The heat input, in million Btu's, used for calculating oxides of nitrogen allowance allocations for each subject unit under this rule shall be the unit's average of the 2 highest heat inputs for the annual control period in the 5 years immediately preceding the year in which the department is required to submit the oxide of nitrogen allocations. ***Notwithstanding the preceding, multi-fueled EGUs may choose to average any two (2) of the annual control period heat inputs in the 5 years immediately preceding the year in which the department is required to submit the oxide of nitrogen allocations.*** If the unit operated less than 2 full years of the 5-year time period, then the unit's single highest heat input shall be used.

Comment: For multi-fueled EGUs, the two highest annual heat inputs may not correspond to the highest adjusted heat input rate when considering the weighted average FAFs. Therefore, such units should be allowed to use any two (2) of the annual control period heat inputs within the appropriate five year period in order to determine the heat input rate used for allocations.

Rule 831

831(2)(a)-(c)

(a) The oxides of nitrogen allowance allocation request shall be submitted before September 1 of the year of the first annual control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the ***EGU***~~oxides of nitrogen unit~~, if required, and each following year by September 1.
(b) The allocation methodology used for the first annual control period for which each new EGU requests allowances shall be calculated using the following formula:

[equation not shown]

Where:	
Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on ***gross*** electric generation.
Size of the unit =	The maximum design capacity of the EGU in ***gross*** megawatts.
Hours of Operation =	Predicted hours of operation per control period.
MWh =	Megawatt hours.

(c) The allocation methodology used for each consecutive annual control period for which each new EGU requests allowances shall be calculated using the following formula:

[equation not shown]

Where:	
Allocation =	The unadjusted NOx allowance allocation, in tons.
1.0 lb NOx/MWh =	The factor for allocating NOx allowances based on ***gross*** electric generation.
Actual megawatt hours =	The actual ***gross*** megawatt hours of electricity generated during the control period immediately preceding the request.
MWh =	Megawatt hours.

Comment: The term "oxides of nitrogen unit" is not defined and should be replaced with the term "EGU". As discussed in relation to Rule 823, the NOx allocation factor must be specified on a gross or net basis. We suggest that gross electrical output be used for allocation purposes.

General Comment – 40 CFR 60, Subpart Da indicates that an output based limit of 1.0 lb/MWh is approximately equivalent to an input based limit of 0.11 lb/mmBtu. It is possible that a new unit will have a NOx emission limitation of less than 1.0 lb/MWh due to BACT, LAER, etc. Should the allocation factor for new units be the more stringent of 1.0 lb/MWh or the permitted emission limit, the average of 1.0 lb/MWh and the emission limit (similar to the allocation concept for existing units), or some other method?

Rule 832

832(2)(b)

(b) Hardship allowances may be allocated to an EGU~~-or non-EGU~~, if the requesting authorized account representative demonstrates both of the following:

Comment: Non-EGUs are not included in the CAIR NOx annual program, and the reference to non-EGU should therefore be deleted.

832(2)(c)(i)

(i) Historical heat input utilization levels shall be based on the ***annual heat input determined in accordance with R 336.1830(4)***~~unit's average of the 2 highest heat input utilization levels for the annual control period in the 5 years immediately preceding the year in which the department is required to submit the oxides of nitrogen allocations to the U.S. environmental protection agency. If the unit operated less than 2 years during the 5-year time period, then the unit's single highest heat input level shall be used~~.

Comment: The heat input rate used for this allocation should be consistent with the heat input rate used for allocations under Rule 830.

832(3)(a)(i) and (b)

(3) The department shall allocate CAIR NOx annual hardship allowances to existing CAIR NOx units which have submitted an engineering analysis as described as follows:
(a) The authorized account representative shall demonstrate to the department that the control level required pursuant to this rule results in excessive or prohibitive cost for compliance. The demonstration shall include all of the following:
(i) An engineering study analyzing all control options that are technically available for the unit, including control options that would achieve a level of control meeting, at a minimum, ***the levels specified in subrules (A) and (B)***~~a 0.15 pound per million Btu emission rate~~.
(A) For the time period between 2009 and 2014, a NOx emission rate of 0.15 pound per million Btu.
(B) For 2015 and beyond, a NOx emission rate of 0.125 pound per million Btu.
(ii) The annualized cost associated with each control option. An annualized cost of more than $2,400 per ton of oxides of nitrogen reduced shall generally be considered to be an excessive cost for compliance with this rule.
(iii) Other considerations that contribute to prohibitive cost of compliance.
(b) For a source to remain eligible for hardship allowances under this rule after the initial 3-year allocation period, ending on ~~September 30~~***December 31***, 2011, the state may require a revised engineering analysis and demonstration as detailed under subrule (3)(a) of this rule, at a minimum of once every 3 years.

Comment: In regards to the hardship allowances, the target NOx emission rate should be consistent with the NOx emission rate used for allocation purposes. In addition, the initial 3-year allocation period will end on December 31, 2011 (not September 30, 2011).

Rule 833

No comments.

Rule 834

No comments.

CMS GENERATION CO.
COMMENTS ON PROPOSED AMENDMENTS TO MICHIGAN AIR POLLUTION CONTROL RULES
SOAHR 2005-037EQ
(NO_X CAIR RULES)

CMS Generation Co. (CMS) offers the following comments on the proposed NO_X CAIR rules on behalf of the following affected or potentially affected facilities in Michigan: Dearborn Industrial Generation (DIG), Genesee Power Station, Grayling Generating Station, Kalamazoo River Generating Station, Livingston Generating Station, and TES Filer City Station. CMS has ownership interest in and operates each of these six facilities, and participated in the MDEQ NO_X CAIR rules development workgroup. All of the following comments are intended to be consistent with our understanding of workgroup discussions and to help clarify rule applicability. They are presented in the sequential order in which the proposed rules are written. Text proposed to be added is shown in ***<u>bold italic underline</u>***. Text proposed to be deleted is shown in ~~strikethrough~~.

<u>Rule 802a</u>

No comments.

<u>Rule 803</u>

803(3)(c)(i)

(c) "Commence operation" as defined in 40 C.F.R. Part 97, solely for purposes of 40 C.F.R. Part 97, subpart HHHH, for a unit that is not currently a CAIR NO_X Ozone Season unit under R 336.1803(3)(d) means the following:
(i) On the later of November 15, 1990, or the date the unit commences operation and that subsequently becomes such a CAIR NO_X ozone season unit, the unit's date for commencement of operation shall be the date on which the unit becomes a CAIR NO_X ozone season unit under R 336.1803(3)(d).

Comment: The highlighted references to rule 803(3)(d) appear to be intended as a reference to a definition for "CAIR NOX ozone season unit." However, 803(3)(d) is the definition of "EGU," and the reference seems to be incorrect. There actually is no definition of "CAIR NOX ozone season unit" to be found in Rule 803. We note that Rule 821(1)(b) references the definition of "ozone season CAIR NOX unit" found in 40 CFR Part 97, and we suggest that the highlighted references above could be replaced with "40 CFR Part 97."

803(3)(j)

(j) "Michigan non-EGUs" means the following:
(i) For units that commenced operation before January 1, 1997, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1995 or 1996 a generator producing electricity for sale.
(ii) For units that commenced operation on or after January 1, 1997, and before January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1997 or 1998 a generator producing electricity for sale.
(iii) For units that commence operation on or after January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and to which either of the following provisions applies:
(A) The unit at no time serves a generator producing electricity for sale.
(B) The unit at any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of 25 megawatts or less and has the potential to use not more than 50% of the potential electrical output capacity of the unit.
(iv) Any unit that met the definition of EGU under the NO_X budget trading program and also meets the definition of cogeneration unit under 40 C.F.R. §96.302.

> *Comment:* Two DIG combined-cycle gas turbine units meet the CAIR cogeneration unit definition, and would otherwise be exempt from CAIR, except for the fact that they were included in the original ozone season NO_X budget trading program. Although they were included in that program as EGUs, US EPA later provided guidance that cogeneration units should have been considered non-EGUs under that program. Under the definitions of "Michigan EGUs" at 803(3)(h) and the unmodified "Michigan non-EGUs" at 803(3)(j), these two DIG units would continue to be considered EGUs. We note that Rule 821(1)(b) correctly extends applicability of the CAIR ozone season program to these units, but it doesn't identify which budget (EGU or non-EGU) they fall under. The proposed language is intended to correctly identify where these units belong.

Rule 821

821(3)

(3) After January 1, 2008, any Michigan EGU that does not utilize fossil fuels of any kind for the production of electricity is determined to be exempt from R 336.1802a to R 336.1834. ***Any EGU wishing to qualify for this exemption shall submit, no later than 30 days after the effective date of this rule, an application for a permit modification to include a federally-enforceable requirement to eliminate the use of fossil fuel in the production of electricity no later than January 1, 2008.***

<u>(a) If the US environmental protection agency approves this subrule (3) after June 1, 2007, the department will, if necessary, develop with the affected EGU an enforceable order establishing a deadline after January 1, 2008 for completion of installation and testing of any modifications to accommodate such elimination of fossil fuels. Such EGU shall not be eligible for an allocation of NO_X ozone season allowances under Rule 822 or NO_X annual allowances under Rule 830, and if necessary the department shall proportionately redistribute any such allowances listed as allocated to such unit to the remaining EGUs, and provide a corrected allowance allocation submittal to the US environmental protection agency.</u>
<u>(b) If the US environmental protection agency disapproves the exemption described in this subrule (3) after June 1, 2007, the department will, if necessary, develop with the affected EGU an enforceable order establishing a deadline after January 1, 2008 for completion of installation and testing of CEMS required under 40 CFR Part 96.</u>

Comment: We appreciate the efforts MDEQ has made to try to keep biomass units that historically have burned *de minimis* amounts of fossil fuel out of the NO_X CAIR program entirely. We believe this proposal is a reasonable accommodation, and we are seeking bids on replacement of natural gas-fired start-up burner systems at our two biomass facilities. We are, however, concerned that there has been no formal guidance from EPA Clean Air Markets Division (CAMD) as to whether this is an approvable rule. To meet the January 1, 2008 deadline, our biomass plants are in the difficult position of needing to make a decision by about June 1 as to whether to spend significant capital on either (i) replacing start-up burner systems with systems that will burn a non-fossil fuel such as biodiesel or (ii) upgrading CEMS to meet 40 CFR 75 monitoring requirements. Until we have clear direction from CAMD as to the approvability of this subrule, we cannot commit to actions (including the submittal of an application for a permit modification) associated with elimination of the use of fossil fuel in these units.

The language shown above is intended to allow an enforceable extension of the January 1, 2008 compliance date for either eliminating fossil fuel or installing CEMS, assuming lack of direction from US EPA on the approvability of this subrule by June 1. There may be other ways of accomplishing this same result – we are simply seeking assurance from MDEQ that it will work with our biomass facilities to avoid enforcement sanctions should a delay in formal guidance from EPA CAMD cause delay of completion of one of the above-described capital projects beyond January 1, 2008.

We also note that although this exemption is targeted towards three biomass units in the state, it potentially could be used by any EGU willing to accept the enforceable limitation on burning fossil fuel. Unless MDEQ has received clear direction from CAMD that it will allow the exemption, and clear indication from an affected EGU that it wishes to apply for the exemption by the time MDEQ submits the 2009 – 2011 allocations to EPA, MDEQ must allocate allowances to all EGUs. If the entire budget for EGUs is allocated for example, just to the non-biomass units, it will be very difficult for MDEQ to "take back" a few from each EGU to reinstate the allocation to the affected biomass units, should EPA later disapprove the exemption. On the other hand, if the allowances are allocated to all units, it will be fairly straightforward to reallocate them out to the non-exempted EGUs, should any units claim the exemption. The proposed language in the last sentence of paragraph (a) is intended to accomplish this result. Again, there may be other ways of doing this – we are just looking for assurance that our biomass units would have an allocation of allowances should EPA disapprove the exemption, or we elect not to use it even if it is approved.

821(4)

(4) The fuel type adjusted allocations for each EGU shall be determined by multiplying the appropriate coefficient ***("fuel adjustment factor")*** as follows:

Comment: Rules 822 and 830 both refer to use of "the appropriate fuel adjustment factor" in determining unit allocations; however, that term is never defined. The proposed language is intended to clarify what the "fuel adjustment factors" are.

Rule 822

822(1)

Rule 822. (1) The CAIR NOx ozone season trading program budget allocated by the department under subrule (3) of this rule for the CAIR NOx ozone season control periods to the EGUs, non-EGUs, and renewable units shall ***annually*** equal the total number of tons of oxides of nitrogen emissions as indicated in the following manner:

Comment: The budget amounts described in the rest of this subrule could perversely be interpreted as totals for the entire period of years described in each paragraph or subparagraph, instead of annual budget totals. The proposed language is intended to clarify the annual applicability of the budget amounts.

822(2)

(2) CAIR NOx allowances for the 2009 ozone season control period shall be the same allowances as were allocated under the NOx budget trading program. For newly-affected EGUs which were not subject to the federal NOx budget program, ~~their~~ ***these*** units are eligible ***to apply*** for allowances from the CAIR NOx ozone season new source set-aside pool for the 2009 ozone season, pursuant to R 336.1823.

Comment: Rule 823 requires that newly-affected units apply for allowances from the new source set-aside pool. The proposed language is intended to clarify that the allowances are not just automatically granted.

822(3)(a)(i)

(3) The department shall allocate CAIR NOx ozone season allowances to existing EGUs and non-EGU ozone season units for calendar years 2010 and thereafter according to the following schedule:
(a) A 3-year allocation that is 3 years in advance of the ozone season control period in which the allowances are to be used. The 3-year allocation shall be as follows:
(i) By 60 days after the effective date of this rule ~~or April 30, 2007, whichever is earlier~~, the department shall submit to the U.S. environmental protection agency the CAIR NOx ozone season allowance allocations, under this subrule, for the ozone season control periods in 2010 and 2011.

Comment: It is unlikely these rules will become effective prior to April 30, 2007, but even if they do, the regulated community will need time <u>after</u> the effective date of the rule to, for example, apply for hardship allowances, which are to be allocated under Rule 824(2)(c)(iii) in 3-year blocks in accordance with this Rule 822(3). However, in accordance with Rule 824(1), such hardship requests must be made at least "30 days prior to the deadline for departmental submittals to the US environmental protection agency as described in R336.1822." If MDEQ wants any time to process such hardship allocation requests, we suggest that 60 days after the effective date of the rule is the minimum needed prior to the initial submittal.

822(3)(a)(iii)

(3) The department shall allocate CAIR NOx ozone season allowances to existing EGUs and non-EGU ozone season units for calendar years 2010 and thereafter according to the following schedule:
(a) A 3-year allocation that is 3 years in advance of the ozone season control period in which the allowances are to be used. The 3-year allocation shall be as follows:
…
(iii) By October 31, 2011, and thereafter each October 31 of the year that is 3 years after the last year of allocation submittal, the department shall submit to the U.S. environmental protection agency the CAIR NOx ozone season allowance allocations as indicated under this subrule<u>***, for the next three ozone season control periods***</u>.

Comment: Subrules (3)(a)(i) and (ii) specify the ozone season control periods for which the department shall submit allowance allocations. This language is intended to clarify that each subsequent submittal is for the next three control periods.

822(4)(a)(i)

(4) For the CAIR NOx ozone season control periods under subrule***s (1)(a) and (b)*** ~~(3)~~ of this rule, the department shall allocate allowances to existing EGU and non-EGU ozone season units that commenced operation before January 1 of the most recent year of the 5-year period used to calculate heat input as follows:
(a) The department shall allocate allowances to each existing EGU ozone season unit as follows:
(i) During calendar years 2010 to 2014 as follows:
(A) Units with an allowable ***NOx*** emission rate equal to or greater than the CAIR target budget rate of 0.15 pounds per million Btu***, and units with no applicable NOx emission rate,*** shall receive ***an initial unadjusted allocation of*** allowances in an amount equaling 0.15 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.
(B) Units with an allowable ***NOx*** emission rate less than the CAIR target budget rate of 0.15 pounds per million Btu shall receive ***an initial unadjusted allocation of*** allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate***:***~~.~~

[equation not shown]

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2009 to 2014 ***(0.15 lb/mmBtu)***.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate ***(lb/mmBtu)***.
HI =	Average of the unit's 2 highest heat inputs for the appropriate 5 control periods ***(mmBtu)***.

Comment: The reference to subrule (3) appears to be incorrect. The correct reference appears to be subrules (1)(a) and (b), as is stated in the comparable location of Rule 830.

The “units with no applicable NO_X emission rate” language in (4)(a)(i)(A) is intended to clarify coverage for any so-called “grandfathered” unit whose installation may have pre-dated any NO_X emission limit.

The “initial unadjusted allocation of” language is intended to clarify that the units will not necessarily receive the allowances calculated according to the formula (as written, the “units…shall receive allowances”). The initial allocation may later be adjusted in subrule (5).

The changes in the table following the equation are intended to clarify what units the various terms are expressed in.

822(4)(a)(ii)

(4) For the CAIR NOx ozone season control periods under subrule***s (1)(a) and (b)*** ~~(3)~~ of this rule, the department shall allocate allowances to existing EGU and non-EGU ozone season units that commenced operation before January 1 of the most recent year of the 5-year period used to calculate heat input as follows:
(a) The department shall allocate allowances to each existing EGU ozone season unit as follows:
…
(ii) During calendar years 2015 and thereafter as follows:
(A) Units with an allowable ***NOx*** emission rate equal to or greater than the CAIR target budget rate of 0.125 pounds per million Btu***, and units with no applicable NOx emission rate,*** shall receive ***an initial unadjusted allocation of*** allowances in an amount equaling 0.125 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.
(B) Units with an allowable ***NOx*** emission rate less than the CAIR target budget rate of 0.125 pounds per million Btu shall receive ***an initial unadjusted allocation of*** allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit’s allowable emission rate, which is then multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate***:***~~.~~

[equation not shown]

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2015 and thereafter ***(0.125 lb/mmBtu)***.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate ***(lb/mmBtu)***.
HI =	Average of the unit's 2 highest heat inputs for the appropriate 5 control periods ***(mmBtu)***.

Comment: These changes are identical to those in 822(4)(a)(i), except for using the appropriate "2015 and thereafter" target emission rate.

822(5)

(5) If the initial total number of CAIR NOx ozone season budget allowances allocated to ***either*** all existing EGU ~~and~~ ***or all existing*** non-EGU ozone season units for the years under subrule (4) of this rule does not equal the ***budgeted*** tons ***for such units*** as specified in subrule (1) of this rule, then the department shall adjust up or down the total number of CAIR NOx ozone season budget allowances allocated to ~~all CAIR NOx ozone season units~~ ***each existing EGU or non-EGU, as appropriate,*** so that the total number of CAIR NOx ozone season budget allowances allocated ***to the entire group of EGUs or non-EGUs*** equals the ***the appropriate*** value~~s~~ in subrule (1) of this rule. The adjustment shall be made by multiplying each unit's ***unadjusted initial*** allocation by a correction factor determined by dividing the ~~total number of the~~ ***the appropriate existing EGU or non-EGU total*** budget tons ~~being allocated~~ ***from subrule (1) of this rule*** by the sum of all ***existing EGU or non-EGU*** units' ***initial unadjusted*** allocations***, and rounding to the nearest whole ton, as appropriate***.

Comment: As written, the total allocation to all EGUs and non-EGUs lumped together would be compared to the total budget for the two together, and would have been adjusted up or down together. This is inconsistent with keeping the two budgets and pools separate. Adjustments to allocations should be done to EGUs as a group separately from non-EGUs as a group. The proposed language is intended to accomplish that separation.

Rule 823

823(2)(b)

(2) The CAIR authorized account representative of a newly-affected CAIR NOx ozone season EGU under this rule may submit to the department a request, in a format specified by the department, to receive CAIR NOx ozone season

allowances for the 2009 CAIR NOx ozone season control period. All of the following apply:
…
(b) The CAIR authorized account representative of any newly-affected EGU may request 2009 CAIR NOx ozone season allowances, based on an amount equaling 0.15 pounds per million Btu multiplied by the unit's ***appropriate fuel adjustment factor as defined in R336.1821 and multiplied by the unit's*** ozone season heat input, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

Comment: The fuel adjustment factor was left out of this calculation.

823(3)

(3) The CAIR authorized account representative of a new CAIR NOx ozone season non-EGU under this rule may submit to the department a request, in a format specified by the department, to receive CAIR NOx ozone season allowances ~~for the CAIR NOx ozone season control period~~***, starting with the ozone season control period during which the CAIR NOx ozone season unit commenced or is projected to commence operation and ending with the control period preceding the control period for which it shall receive an allocation under R 336.1822*****.** Both of the following apply:

Comment: This subrule applies to new non-EGUs. The proposed language comes from the same requirement for new EGUs in Rule 823(4), and is needed for clarity.

Rule 824

824(2)(c)(ii)

(2) For existing EGUs and non-EGUs subject to the CAIR NOx ozone season budget, the department shall allocate CAIR NOx hardship allowances under the following procedures:
…
(c) The CAIR authorized account representative of a CAIR NOx ozone season unit under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx ozone season hardship allowances. The authorized account representative shall submit the request for the amount of estimated hardship allowances they need, using historical ozone season heat input utilization levels multiplied by historical oxides of nitrogen emission rates as follows:
…
(ii) Historic oxides of nitrogen rates shall be based on the oxides of nitrogen rate reported by the authorized account representative in its 40 C.F.R. part 75 reports to the U.S. environmental protection agency in the calendar year immediately

preceding the year in which the department is required to submit the oxides of nitrogen allocation***, or as determined by other similar quality-assured data for units not required to monitor in accordance with 40 C.F.R. part 75***.

> *Comment:* Some units may not be required to monitor in accordance with 40 CFR 75 requirements prior to 2008.

Rule 825

825(7) [NEW]

(7) If the renewable allocation set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, then the department shall proportionately reduce the number of CAIR NOx ozone season allowances allocated to each CAIR NOx ozone season unit requesting such allowances, so that the total number of CAIR NOx ozone season allowances allocated are equal to the amounts in R 336.1822(1)(a)(iv) or (b)(iv).

> *Comment:* This is needed in case the renewable pool is oversubscribed.

Rule 826

> No comments.

Rule 830

830(1)

Rule 830. (1) The CAIR NOx annual trading program budget allocated by the department for the CAIR NOx annual control periods shall ***annually*** equal the total number of tons of oxides of nitrogen emissions as follows and apportioned to the CAIR NOx EGUs, as determined by the procedures in this rule. These allocations shall be distributed in the following manner:

> *Comment:* Same comment as for Rule 822(1)…The budget amounts described in the rest of this subrule could perversely be interpreted as totals for the entire period of years described in each paragraph or subparagraph, instead of annual budget totals. The proposed language is intended to clarify the annual applicability of the budget amounts.

830(2)(a)

(2) The department shall allocate CAIR NOx annual budget allowances to existing CAIR NOx units. A 3-year allocation is 3 years in advance of the annual

control period in which the allowances are to be used. The 3-year allocation shall be as follows:
(a) By 60 days after the effective date of this rule ~~or April 30, 2007, whichever is earlier~~, the department shall submit to the U.S. environmental protection agency the CAIR NOx annual allowance allocations, under subrule (3) of this rule, for the annual control periods in 2009, 2010, and 2011.

> *Comment:* Same comment as for Rule 822(3)(a)(i)… It is unlikely these rules will become effective prior to April 30, 2007, but even if they could, the regulated community will need time after the effective date of the rule to, for example, apply for hardship allowances, which are to be allocated under Rule 832(2)(c)(iii) in 3-year blocks in accordance with this Rule 830(2). However, in accordance with Rule 832(1), such hardship requests must be made at least "30 days prior to the deadline for departmental submittals to the US environmental protection agency as described in R336.1830." If MDEQ wants any time to process such hardship allocation requests, we suggest that 60 days after the effective date of the rule is the minimum needed prior to the initial submittal.

830(2)(c)

(2) The department shall allocate CAIR NOx annual budget allowances to existing CAIR NOx units. A 3-year allocation is 3 years in advance of the annual control period in which the allowances are to be used. The 3-year allocation shall be as follows:
…
(c) By October 31, 2011, and thereafter each October 31 of the year that is 3 years after the last year of allocation submittal, the department shall submit to the U.S. environmental protection agency the CAIR NOx annual allowance allocations as indicated under subrule (3) of this rule***, for the next three annual control periods***.

> *Comment:* Subrules (2)(a) and (b) specify the annual control periods for which the department shall submit allowance allocations. This language is intended to clarify that each subsequent submittal is for the next three annual control periods.

830(3)(a)

(3) For the CAIR NOx annual control periods under subrules (1)(a) and (b) of this rule, the department shall allocate allowances to existing EGU units that commenced operation before January 1 of the most recent year of the 5-year period used to calculate heat input. The department shall allocate the following allowances to each existing CAIR NOx unit:
(a) During calendar years 2010 to 2014:
(i) Units with an allowable ***NOx*** emission rate equal to or greater than the CAIR target budget rate of 0.15 pounds per million Btu***, and units with no applicable***

NOx emission rate, shall receive ***an initial unadjusted allocation of*** allowances in an amount equaling 0.15 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.
(ii) Units with an allowable ***NOx*** emission rate less than the CAIR target budget rate of 0.15 pounds per million Btu shall receive ***an initial unadjusted allocation of*** allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate***:***~~.~~

[equation not shown]

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2009 to 2014 ***(0.15 lb/mmBtu)***.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate ***(lb/mmBtu)***.
HI =	Average of the unit's 2 highest heat inputs for the appropriate 5 control periods ***(mmBtu)***.

Comment: Same as for Rule 822(4)(a)(i)…

The "units with no applicable NO_X emission rate" language in (3)(a)(i) is intended to clarify coverage for any so-called "grandfathered" unit whose installation may have pre-dated any NO_X emission limit.

The "initial unadjusted allocation of" language is intended to clarify that the units will not necessarily receive the allowances calculated according to the formula (as written, the "units…shall receive allowances"). The initial allocation may later be modified in subrule (5).

The changes in the table following the equation are intended to clarify what units the various terms are expressed in.

830(3)(b)

(3) For the CAIR NOx annual control periods under subrules (1)(a) and (b) of this rule, the department shall allocate allowances to existing EGU units that commenced operation before January 1 of the most recent year of the 5-year

period used to calculate heat input. The department shall allocate the following allowances to each existing CAIR NOx unit:

…

(b) During calendar years 2015 and thereafter the following apply:

(i) Units with an allowable ***NOx*** emission rate equal to or greater than the CAIR target budget rate of 0.125 pounds per million Btu***, and units with no applicable NOx emission rate,*** shall receive ***an initial unadjusted allocation of*** allowances in an amount equaling 0.125 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(B) Units with an allowable ***NOx*** emission rate less than the CAIR target budget rate of 0.125 pounds per million Btu shall receive ***an initial unadjusted allocation of*** allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate***:***~~.~~

[equation not shown]

Where:

Allocation =	The unadjusted NOx allowance allocation, in tons.
CTER =	The CAIR target emission rate for 2015 and thereafter ***(0.125 lb/mmBtu)***.
FAF =	Fuel adjustment factor as defined in R 336.1821.
AER =	The unit's allowable emission rate ***(lb/mmBtu)***.
HI =	Average of the unit's 2 highest heat inputs for the appropriate 5 control periods ***(mmBtu)***.

Comment: These changes are identical to those in 830(3)(a), except for using the appropriate "2015 and thereafter" target emission rate.

830(5) ***[NEW]***

(5) If the initial total number of CAIR NOx annual budget allowances allocated to all existing EGUs for the years under subrule (3) of this rule does not equal the budgeted tons for such units as specified in subrule (1) of this rule, then the department shall adjust up or down the total number of CAIR NOx annual budget allowances allocated to each existing EGU so that the total number of CAIR NOx annual budget allowances allocated to the entire group of EGUs equals the appropriate value in subrule (1) of this rule. The adjustment shall be made by multiplying each unit's unadjusted initial allocation by a correction factor determined by dividing the

<u>appropriate existing EGU total annual budget tons from subrule (1) of this rule by the sum of all existing EGUs' initial unadjusted allocations, and rounding to the nearest whole ton, as appropriate.</u>

Comment: Rule 830 is missing necessary language to adjust individual EGU allocations so that the sum over all EGUs equals the total budget amount.

<u>Rule 831</u>

No comments.

<u>Rule 832</u>

832(2)(c)(ii)

(2) For existing EGUs subject to the CAIR NOx annual budget, the department shall allocate CAIR NOx hardship allowances under the following procedures:
…
(c) The CAIR authorized account representative of a CAIR NOx unit under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx annual hardship allowances. The authorized account representative shall submit the request for the amount of estimated hardship allowances they need, using historical annual heat input utilization levels multiplied by historical oxides of nitrogen emission rates, in the following manner:
…
(ii) Historic oxides of nitrogen rates shall be based on the oxides of nitrogen rate reported by the authorized account representative in its 40 C.F.R. part 75 reports to the U.S. environmental protection agency in the calendar year immediately preceding the year in which the department is required to submit the oxides of nitrogen allocation***<u>, or as determined by other similar quality-assured data for units not required to monitor in accordance with 40 C.F.R. part 75</u>***.

Comment: Same comment as for Rule 824(2)(c)(ii)…Some units may not be required to monitor in accordance with 40 CFR 75 requirements prior to 2008.

<u>Rule 833</u>

833(3)(b)

(3) The department shall issue hardship allowances to newly-affected EGUs for which compliance with the CAIR NOx emissions limitations would create an undue risk to the reliability of electricity supply during the 2009 control period. The CAIR NOx authorized account representative of the CAIR NOx unit may request the allocation of CAIR NOx allowances from the compliance supplement pool under subrule (1)(b) of this rule, pursuant to the following:

…

(b) The CAIR NOx authorized account representative shall demonstrate that, in the absence of allocation of the amount of CAIR NOx allowances requested, the unit's compliance with the CAIR NOx emissions limitation for the 2009 control period would create an undue risk to the reliability of electricity supply during the 2009 control period. This demonstration shall include ~~both~~ ***at least one*** of the following:

(i) A showing that it would not be possible for the owners and operators of the unit to ***economically*** comply with applicable control measures by obtaining sufficient amounts of electricity from other electric generation facilities during the installation of control technology at the unit.

(ii) A showing that it would not be possible for the owners and operators of the unit to ***economically*** comply with applicable control measures by acquiring sufficient allowances from other sources or persons.

> *Comment:* The newly-affected units are in a unique situation with respect to all other affected units around the country – they are subject to the CAIR ozone-season program, but receive no 2009 allocation of ozone-season NO_X allowances, because they were not part of the NO_X SIP Call program (either due to geographic location within Michigan or due to the difference in definition of "fossil fuel" between the NO_X SIP Call and CAIR). We should not be penalizing these units simply due to these unlucky circumstances. Rule 833(3) is intended to address the shortfall of allowances that may occur for these newly-affected units, if they are unable to obtain sufficient allowances from the ozone-season new unit pool under Rule 823(2).
>
> As written, Rule 833(3)(b) is more stringent than the compliance supplement pool requirements in 40 CFR 96.143(c)(2), which require a unit to make one demonstration or the other, but not both. This, combined with the failure to include economic considerations, creates an insurmountable burden for these units. It can be argued that these units could always buy electricity or allowances from someone else – it's just a question of how much it costs. The proposed language is intended to clarify that these newly-affected units should be required to make a reasonable demonstration to qualify for the supplemental 2009 allowances.

Rule 834

> No comments.

CMS appreciates the opportunity to participate in the development of these rules, and the willingness of MDEQ staff and management to work with the affected parties to come up with a reasonable allocation scheme. We look forward to continued close cooperation during the implementation phase. Please contact Mike Weber at (517) 768-7442 or Mark Fletcher at (313) 336-7189 if you have any questions.

Detroit Edison Company Comments

Michigan Proposed Rules R 336.1802a through R 336.1834 (SOAHR 2005-037EQ) April 2, 2007

Detroit Edison generates, transmits and distributes electricity to 2.2 million customers in southeastern Michigan. The proposed rules developed to address requirements of the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR) will significantly affect Detroit Edison. We appreciate the stakeholder process utilized by the Department of Environmental Quality (DEQ) to develop these proposed rules and appreciate the opportunity to provide these additional comments.

It has been recognized that EPA included Michigan's biomass units in the program without including their heat input values in the determination of the budgets. DEQ has agreed to exempt any biomass units that restrict their fuel usage to biomass only (eliminating all fossil fuels) by January 1, 2008. Rules 803 and 821 have been revised to address this issue. We support this exemption and suggest no further delay in implementation of this rules package, possibly resulting in EPA imposition of the Federal Implementation Plan (FIP), because of the addition of this exemption.

Comments - Rule 803

(3)(g)(iii)
Add "coke oven gas" to "Gaseous fuel" definition.

(3)(h) through (l)
Detroit Edison's Harbor Beach Power Plant is located outside of the identified "Michigan fine grid zone." While also geographically outside of the "fine grid zone" for NOx SIP Call purposes, Harbor Beach Power Plant was at that time specifically identified as an affected source. By definition with the currently proposed Rule 803, the plant would be identified as a "newly-affected EGU." Since Harbor Beach Power Plant is already an affected source under the NOx SIP Call, it should also be specifically identified as an affected source for purposes of this rule.

(3)(o)
"Geographic area" should be specifically identified. Since counties are used to specifically identify the geographical area for the "Michigan fine grid zone" in (3)(i), we recommend identification of the geographical area for (3)(o) to also be identified as within the same county.

Detroit Edison Comments
Michigan CAIR Rule Package - Part 8 Rules
(SOAHR 2005-037EQ)
April 2, 2007

Comments - Rule 821

(1)(c)(ii)
Change "Renewable source projects" to "Renewable energy projects" to be consistent with definition in Rule 803 (3)(o).

Comments - Rule 822

Rule 822 (4)(a)(i)(A) identifies 0.15 pounds per million Btu as the "CAIR target budget rate" for 2009 through 2014 (Line 394/395). The formula in Rule 822 (4)(a)(i)(B) (line 408) identifies this same value as "CTER = CAIR target emission rate." These should be identically identified.

Rule 822 (4)(a)(ii)(A) identifies 0.125 pounds per million Btu as the "CAIR target budget rate" for 2015and thereafter (Line 411/412). The formula in Rule 822 (4)(a)(ii)(B) (line 425) identifies this same value as "CTER = CAIR target emission rate." These should be identically identified.

Thank you for the opportunity to participate in the stakeholder process and to provide these comments.

Respectfully Submitted,

William Rogers
Senior Technological Specialist – Environmental Strategies

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Mackinaw Power®

Protecting Our Great Lakes For Future Generations

April 2, 2007

To: Michigan Department of Environmental Quality, Air Quality Division (MDEQ AQD)

From: Richard F. Vander Veen, President, Mackinaw Power

Re: MDEQ AQD Clean Air Interstate Rules (CAIR)

We appreciate your time and consideration. Today, I have the privilege of presenting a letter which we have co-signed with Environmental Resources Trust and the Michigan Environmental Council. We stand ready to assist the MDEQ to promulgate and implement the CAIR Rules and related public policies that encourage, new, innovative clean technologies that are competitive and cost–effective. In sum, our letter confirms:

The MDEQ has Authority for the Renewable Energy Set Aside in the CAIR Rules

Michigan Public Policy Should Support Market-Based Clean Air Compliance

MDEQ CAIR Renewable Energy Set Aside Should be EXPANDED Three Percent (3%)

States with successful RE and EE set-asides as part of the NOx SIP call have allocated around ***3 to 5 percent*** of the allowance pool to zero-emission projects. ***The 21st century energy plan report*** and other recent documents highlights a growth potential for renewable energy that is much higher than the amount allocated by the proposed rule. The Michigan RE set-aside should be at least three percent in view of the growth potential for RE in Michigan and the experience of States with successful RE set-asides under existing NOx emission trading rules.

We recommend the following be ADDED: By April 30, 2011, the Department of Environmental Protection shall complete a report reviewing the appropriateness of the future size of the renewable energy set-aside program and any refinements needed

The CAIR Rules should include a requirement for evaluation and authority for the DEQ to expand the Renewable Energy Set Aside

Increased deployment of renewable energy also would be consistent with findings of the Michigan Public Service Commission's recent 21st century energy plan report and enactment of the Michigan Renewable Energy Standard, Senate Bill 213 or House Bill 4562.

Mackinaw Power, L.L.C.
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April 1, 2007

Ms. Theresa Walker
Michigan Department of Environmental Quality
Air Quality Division
P.O. Box 30260
Lansing, Michigan 48909-7760

RE: Proposed Michigan Clean Air Interstate Rule

Dear Ms. Walker:

We are submitting comments on the proposed "Emission Limitations and Prohibitions for Oxides of Nitrogen" as part of Michigan's rulemaking process to implement the Environmental Protection Agency's Clean Air Interstate Rule (CAIR). We applaud the Department of Environmental Quality (DEQ) for including provisions in the proposed rule that set aside NOx allowances for renewable energy (RE) in the ozone season NOx emission trading rule. We appreciate DEQ's efforts to refine various provisions of the rule relating to renewable energy during the course of its working group sessions.

We believe that the CAIR proposal is an important step forward in leveraging the DEQ's authority to promote clean energy for the benefit of all Michigan residents. At the same time, we offer suggestions to improve the proposed rule. We urge DEQ to:

- Increase the amount of allowances for ozone season and annual RE set-asides to at least three percent of the total EGU allowance pool;
- Include a set-aside of NOx allowances for renewable energy sources and projects in its annual trading rule;
- Allow smaller RE projects into the program through aggregation.

General Discussion

This letter is written on behalf of several organizations and individuals. These include the Michigan Environmental Council (MEC), Mackinaw Power, Environmental Resources Trust (ERT), Resource Systems Group (RSG), and DJ Consulting LLC (DJC). MEC represents more than 70 member groups with a combined membership of nearly 200,000 residents to provide a collective voice advocating for the protection of human health and the environment. Mackinaw Power is a leading developer of wind energy in Michigan. ERT is a non-profit environmental and energy group committed to developing market-based solutions to environmental problems. RSG and DJC are consultants with strong expertise in clean energy/air quality integration. All of the co-signors to this letter strongly support policies that promote widespread deployment of renewable energy (RE). Many of the insights reflected in this letter were gained through contract work generously funded by the U.S. Department of Energy's Wind Powering America Program and the National Renewable Energy Laboratory.

The negative impacts of fossil fuel-fired electric power generation are well documented. These facilities emit enormous volumes of smog and soot precursors, including nitrogen oxides (NOx) and fine particulate matter. High levels of ozone have been linked to a host of adverse health effects, including asthma, bronchitis, heart disease and stroke. In fact, one of the major purposes of the Clean Air Interstate Rule (CAIR) is to reduce long-distance transport of NOx emissions.

In addition, fossil fuel-fired power plants are a major source of greenhouse gas emissions linked to climate change. Scientific consensus points to human-released carbon dioxide as the primary driver of global warming. We are beginning to comprehend the scope and magnitude of problems and challenges stemming from atmospheric changes already underway.

Given the multiple health and environmental concerns related to fossil fuel-fired electric generation, there is an undeniable need to deploy more renewable energy generation. Pursuit of this goal also has compelling economic reasons. Michigan is in the midst of a painful transition away from an economy that historically relied on a dependable supply of high-wage manufacturing jobs. Due to fierce global competition and other factors, that economic security no longer exists. Until Michigan attracts and grows new technology-based industries to offset continued job loss from the automotive sector, its future economic prosperity will be in question.

Fortunately, recent studies have concluded that Michigan is well positioned to build a strong clean energy sector.[1] These reports conclude that the state can leverage its significant renewable energy potential, existing industrial infrastructure, and intellectual talent to serve both its own domestic energy market and a burgeoning global market for clean energy technologies.

However, only states with proactive policies to spur this sector have successfully attracted major capital investment. Two winners have been Pennsylvania and Wisconsin. Spanish wind turbine producer Gamesa chose Pennsylvania for its new U.S. headquarters and turbine manufacturing facilities leading to the creation of several hundred new jobs. Wind equipment supplier Global Energy Systems is building a new plant in Stevens Point, Wisconsin (100 jobs). By adopting a policy mix in support of RE projects, Michigan can effectively compete for such attractive investments.

Increased deployment of renewable energy also would be consistent with findings of the Michigan Public Service Commission's recent 21st century energy plan report, which recommends that clean energy resources, such as renewable energy and energy efficiency, become more prominent in Michigan's energy portfolio.

Michigan policymakers must make it a priority to remove market barriers to homegrown, clean, efficient sources of energy. Growth in the RE sector will be hampered until clean energy sources can compete on a level playing field with fossil fuel-fired power generation. Such generation has historically received large institutionalized subsidies (both direct and indirect). In fact, under the

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[1] For example, see Renewable Energy Policy Project (REPP): *Wind Turbine Development: Location of Economic Activity*, Sept 2004 (http://www.repp.org/articles/static/1/binaries/WindLocator.pdf) and *Solar PV Development: Location of Economic Activity*, Jan 2005 (http://www.repp.org/articles/static/1/binaries/SolarLocator.pdf); and Repowering the Midwest: *Job Jolt*, Oct 2002 (http://www.repowermidwest.org/Job%20Jolt/JJfinal.pdf) and *Job Jolt Michigan Factsheet* (http://www.repowermidwest.org/Job%20Jolt/MI.pdf)

NOx SIP Call, the regulations allocated **all** NOx allowances freely to historic emitters without any allocation to renewable energy. A report of the National Commission on Energy Policy has concluded that such free allocation to historic emitters provides the potential for large windfall profits to power companies.[2] The State of Michigan should use every measure at its disposable, including a strong NOx trading set-aside program for RE, to place renewable energy on a level playing field.

It is entirely appropriate that DEQ promote RE projects through the CAIR rulemaking process. Indeed, EPA has explicitly identified EERE set-asides as an option that States can use to encourage the growth of these clean energy technologies. NOx allowances are not the property of utility companies. EPA has stressed that states have full authority and flexibility in deciding how to allocate NOx allowances under the trading programs. While it is true that inclusion of clean energy sources would not necessarily reduce actual emissions unless credits are retired, the result would be a lower overall compliance cost for all participants.

This approach also furthers the implementation of Governor Granholm's Executive Directive 2006-1, which emphasizes that "The state's economic interest in ensuring development of the intellectual capital, financing, infrastructure, and other resources necessary for continued growth of alternative and renewable energy technologies within the state shall be fostered."

Specific Recommendations

Increase the amount of allowances for ozone season RE set-asides to at least three percent of the total EGU allowance pool or include a reassessment provision.

The proposed number of NOx allowances that are set aside to encourage renewable energy is inadequate for both the ozone season and on an annual basis:

- *For ozone season trading 2010 to 2014*, 200 tons of the 31,180 tons per electric generating unit (EGU) pool is **0.64 percent**. [R 336.1824(2)(a)(i)]
- *For ozone season trading in 2015 and thereafter*, 200 tons of the 26,351 tons in the EGU pool is **0.76 percent**. [R 336.1824(2)(a)(ii)]

These percentages are significantly below the amount set forth in guidance recommended by EPA as well as EERE set-asides established by other States.[3] States with successful RE and EE set-asides as part of the NOx SIP call have allocated around **3 to 5 percent** of the allowance pool to zero-emission projects. For example, the Massachusetts program uses a set-aside of 5 percent, which more accurately reflects the true economic value of clean generators.

Moreover, analysis by the Michigan PUC staff and others in the 21st century energy plan report and other recent documents highlights a growth potential for renewable energy that is much

---

[2] Staff Paper for the National Commission on Energy Policy, "Allocating Allowances in a Greenhouse Gas Trading System," March 2007, p. viii. See http://www.energycommission.org Although the National Commission staff report was focused on trading of greenhouse gas emissions, their finding is equally applicable to NOx emissions trading.

[3] U.S. Environmental Protection Agency, "Guidance on Establishing an Energy Efficiency and Renewable Energy (EE/RE) Set-aside in the NOx Budget Trading Program," March 1999, pp. x-xi.

higher than the amount allocated by the proposed rule.[4] The Michigan RE set-aside should be at least three percent in view of the growth potential for RE in Michigan and the experience of States with successful RE set-asides under existing NOx emission trading rules.

At a minimum, DEQ should include a provision in its rule requiring a reevaluation of the size of the RE set-aside prior to the allocations for the second phase of CAIR. We urge DEQ to incorporate language in the proposed regulation that requires the review of the operation of the EERE set-aside program several years after its establishment. We have set forth suggested language in attachment A. This type of study provision has been proposed by the Connecticut DEP in its NOx budget program under CAIR.

Include a set-aside of NOx allowances for renewable energy sources and projects in its annual trading rule.

Earlier versions of the proposed CAIR circulated by DEQ included a set-aside of 285 NOx allowances to support RE projects in the annual NOx trading rule. Unfortunately, DEQ deleted this set-aside in its proposed rule. The annual allocation to renewable energy projects is particularly important for wind energy projects because these projects typically have a higher capacity during the winter months. We urge you to reconsider this issue and to include this allocation in your final rule.

Allow smaller projects into the program through aggregation.

We appreciate the efforts of DEQ to provide increased aggregation in its proposed rule compared to previous drafts. The proposed rule allows aggregation of "renewable energy sources located within the same geographic area that when added together equal a generator greater than 25 megawatts of electrical output." [R 336.1803(m)] This definition will assure allocation of NOx allowances to most wind farms where turbines of 1 to 2 MW are groups together and would typically exceed 25 megawatts.

However, this definition virtually eliminates solar power from consideration, and this failure is particularly troubling given the growing potential for cost-competitive solar applications and the large economic benefits that would accrue to Michigan with the development of solar energy. Recent solar energy experts have highlighted the likelihood of technical and manufacturing breakthroughs in the next decade that will lead to cost-competitiveness of solar energy in many markets,[5] particularly those markets where high power quality and reliability are critical, such as data processing centers, banks, waste water treatment plants, and emergency shelters. However, solar photovoltaic arrays rarely exceed 1MW, and therefore, the 25 MW limitation will likely preclude the eligibility of solar photovoltaics in the proposed set-aside. The proposed rule should be changed to provide authority for project aggregation.

States with successful set-asides for the NOx SIP Call, such as Massachusetts, have allowed for aggregation of smaller projects, and other States, such as Virginia, have adopted such provisions in their new Clean Air Interstate Rule.

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[4] Michigan Public Service Commission, Appendix F to Capacity Need Forum Staff Report, January 2006. See http://www.dleg.state.mi.us/mpsc/electric/capacity/cnf/cnf_reportvol2_1-3-06.pdf

[5] Travis Bradford, "Solar Revolution: The Economic Transformation of the Global Energy Industry," MIT Press, 2006.

Thank you for your consideration of our views on this important matter. Please let us know if we can answer any questions related to our comments.

Sincerely,

David Gard
Energy Program Director
Michigan Environmental Council
davidmec@voyager.net

Richard F. Vander Veen
President
Mackinaw Power
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Debra Jacobson
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cc: Mr. Steve Chester
Mr. Vince Hellwig
Mr. John Sarver

ATTACHMENT A

By April 30, 2011, the Department of Environmental Protection shall complete a report reviewing the appropriateness of the future size of the renewable energy set-aside program and any refinements needed to facilitate the applications for allowances for RE projects under such program. This review will be issued for public review and comment and shall focus on the following factors:

(1) Projections for the growth of renewable energy development in Michigan;
(2) Utilization of the allowances under the RE set-aside;
(3) Any administrative obstacles that may impede applications for allowances under the program; and
(4) Any benefits of the program in facilitating the attainment of the National Ambient Air Quality Standards.

WHAT CAN 24 STATES TEACH MICHIGAN?
Why Rebuilding Michigan Requires An RPS

By Rich Vander Veen, Mackinaw Power

Twenty-four states have now adopted a Renewable Portfolio Standard (RPS). Michigan can begin to rebuild our economy by learning important lessons from those states where RPS laws ensure that a minimum amount of renewable energy is included in the portfolio of electricity resources serving their states.

Michigan's legislators are bound by our 1963 Constitution's Article IV to properly utilize and regulate energy, while protecting our economy and environment. Article IV, Section 50 provides:

"**The Legislature may provide safety measures and regulate the use of** atomic power and **forms of energy developed in the future, having in view the general welfare of the people of this state**. (emphasis added)."

Fittingly, the 1963 Michigan Constitution mandates that Legislature protect the environment and public health at Article IV, Section 52:

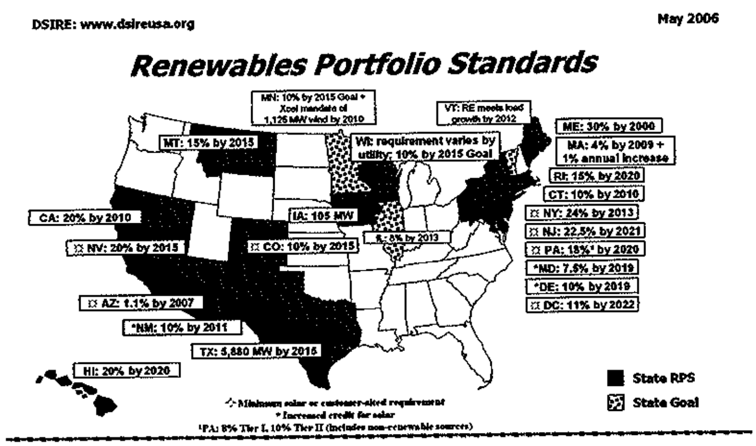
"The conservation and development of the natural resources of the state are hereby declared to be of paramount public concern. The legislature shall provide for the protection of the air, water and natural resources of the state from pollution, impairment and destruction."

The Michigan Legislature has a key opportunity to fulfill its Constitutional requirements by enacting legislation regulating Michigan's electric utilities and protecting Michigan's environment. In 2000 P.A. 141, MCL 460 the Legislature used its constitutional authority under Article IV, Sections 50 <u>and</u> 52 to mandate in Section 10b, that the **Commission "shall establish rates, terms and conditions for…new generation technologies"** such as wind power (emphasis added). Further, under 2000 P.A. 141 Section 10r(6), the **"Commission shall ….encourage the development of new renewable energy**

facilities" (Emphasis added). Michigan Public Service Commission (MPSC) Chairman Peter Lark has delivered the 21st Century Energy Plan, addressing:

A. Short and long term electrical needs assuring a reliable, safe, clean and affordable supply. The Report found that Michigan needs an estimated 5,000+ MW of new generation by 2015.

B. A competitive business climate, new jobs and the use of energy efficiency, alternative and renewable energy technology which protects the State's natural resources. More than $5 billion in new capital investment could help us innovate our way toward energy self sufficiency, reducing our dependence on foreign and fossil fuel.



C. A Michigan RPS: 10% by 2015 and 20% by 2025.

What do opponents of the MI RPS say?

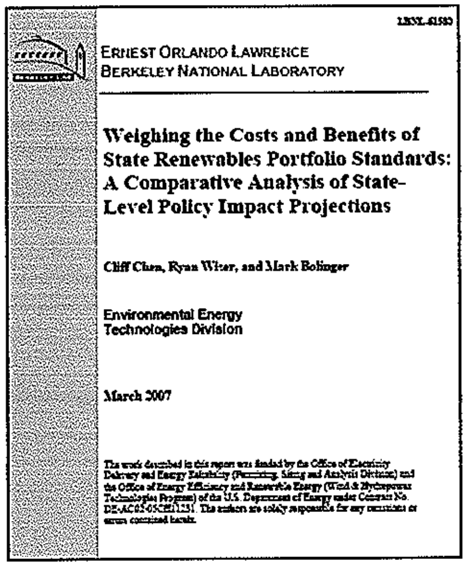
1. The MI RPS should not be mandated

"Mandating the RPS will tie our hands," say Michigan utilities.

Remember, Michigan utilities only respond to clear laws and regulations. It is the Legislature's Constitutional duty to statutorily set the amount of authority under which the MPSC regulates Michigan gas and electricity rates and markets. Without sufficient authority, the MPSC will never be able to enforce a clear, consistent renewable energy standard. Without new, clear authority, a MI RPS is worthless.

2. The MI RPS will increase electricity costs.

"A MI RPS could increase MI electricity rates at a time when we can least afford to do so," say some customers.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ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Weighing the Costs and Benefits of State Renewables Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections

Cliff Chen, Ryan Wiser, and Mark Bolinger

Environmental Energy
Technologies Division

March 2007

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability (Permitting, Siting and Analysis Division) and the Office of Energy Efficiency and Renewable Energy (Wind & Hydropower Technologies Program) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

According to the United States Energy Department-funded exhaustive reports, recently published by the Lawrence Berkley National Laboratory, twenty-eight cost/benefit projections on state RPS laws have been undertaken. Nineteen predicted no more than a one percent (1%) increase. Two said costs would increase more than five percent (5%). Six projections forecast a cost **decrease.**

See http://eetd.lbl.gov/ea/ems/reports/61580.pdf

By approving the Michigan RPS and having the Governor enact it as 2007 Public Act ____, the Legislature will assure that the Michigan RPS will:

1. Increase the required amount of new, Michigan-based electricity, over time.

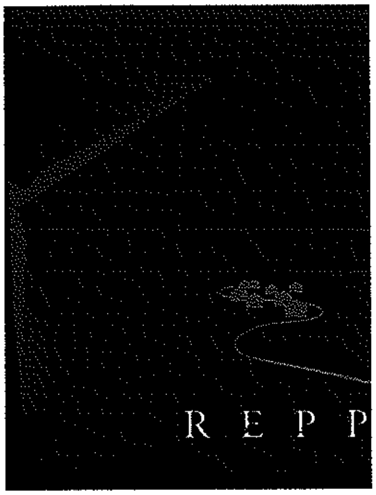
2. Put Michigan on a path toward increasing sustainability.

3. Require the investment of more than $1 million in new infrastructure for each new megawatt (MW) of wind power installed

4. Invest in 21st Century jobs, creating new construction, operating and manufacturing jobs, using state-of-the-art technologies.

The Renewable Energy Policy Project (www.repp.org) underscores that a national RPS of 50,000 MW could create 150,000 national and 8,500 Michigan new manufacturing jobs. This would add more than $400 million in payroll and creating a new industry for Michigan.

5. While the MPSC CNF Report estimated 410 MW of wind is readily available to be developed 2007 – 2012, the models run by the 21st C. Energy plan would increase this to 2,000 + MW.



To be conservative, the 410 MW in new Michigan wind farms will stabilize costs, producing approximately 820,000,000 kilowatt hours (kWh; 820,000 MWh) annually of new, zero-emissions energy. According to the National Renewable Energy Lab's Jobs and Economic Development Index (JEDI), 410 MW of wind power will provide the following financial and community benefits to Michigan over 20 years:

- 273 1.5 MW Wind Turbines = $464 million in capital expenditures
- More than 100,000 homes served with new, clean power
- $140,630,000 in Local Community Benefits
- $27,320,000 in Lease Payments to Michigan Farmers and Landowners
- Increased public health and energy independence.

New wind power will protect our Great Lakes for future generations with cleaner air and water. According to the Consumers Energy biannual report, the 820,000 MWh of new wind power will, each year, offset:

Pollutant	**Consumers Energy Annual Pounds Produced Per MWh**	**Regional Annual Pounds Produced Per MWh**
Sulfur Dioxide (acid rain)	7,511,000	15,334,000
Carbon Dioxide ("Green House Gas)	1,910,108,000	1,717,490,000
Oxides of Nitrogen (Ozone)	2,665,000	5,740,000
High-Level Nuclear Waste	5,000	6,000
Mercury	See MDEQ Mercury Rules	Great Lakes Mercury Rules

7. Market implementation will result in competition, efficiency and innovation that will deliver renewable energy at the lowest possible cost. This will result in cost-effective renewable power.

For example, Wisconsin and Colorado require 10% renewable power by 2015. Both Wisconsin and Colorado have measured the costs and the benefits of renewable power. Both WI and CO have decided to increase the amount of renewables required, AFTER they determined that a growing amount of renewables will cut the risks associated with rising, volatile fossil fuel, emissions and toxic waste.

8. The states with an RPS have also found that they are benefiting from renewables by locking in a long-term firm and competitive price. They have concluded that renewable energy boosts generation portfolio performance, like a bond boosts financial portfolio performance with long-term, stable interest paid. This has led to several RPS states increasing the amount of renewables required under their RPS laws.

In Michigan, the Urban Core Mayors (who represent over 80% of the State's population) have adopted a resolution calling for 15% new Renewable Power by 2015.

You are encouraged to listen to a wide range of your constituents who participated in the Michigan 21st Century Energy work groups. Read about their work at www.michigan.gov/mpsc.

Now is the time for this **Governor and Legislature to adopt and enforce a strong, effective Michigan RPS!**

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

APR 02 2007

REPLY TO THE ATTENTION OF:

(AR-18J)

Teresa Walker
Air Quality Division
Michigan Department of Environmental Quality
P.O. Box 30260
Lansing, Michigan 48909-7760

Dear Ms. Walker:

Thank you for the opportunity to comment on the proposed regulations to address the Clean Air Interstate Rule (CAIR) State Implementation Plan (SIP) requirements. We appreciate this opportunity and the time you have taken to discuss these proposed regulations with us. We have found these discussions useful to provide our opinions as well as gain a better understanding of the provisions found in the proposed regulations.

Region 5 may have additional comments after reviewing the revised language and the supplemental technical support materials which have not yet been submitted for review. We look forward to continuing working with the Michigan Department of Environmental Quality towards a fully approvable CAIR SIP for the State of Michigan. If you have any questions concerning the Region's comments, please feel free to contact me.

Sincerely,

Douglas Aburano

Douglas Aburano
Environmental Engineer
Criteria Pollutant Section

Comments on Michigan CAIR Regulations

336.1803(3) -- Michigan needs to supplement the definition of "Commence commercial operation" with language stating that, for units not serving a generator, the commence operation date is also the commence commercial operation date. This is important because monitoring system certification deadlines are based on the date of commencement of commercial operation, and some CAIR NOx ozone season units in Michigan may not serve generators. See"CAIR Questions and Answers -- SIP Call Transition", http://www.epa.gov/airmarkets/cair/sipcalltrans.html

336.1803(3) – It appears that Michigan intends to allocate allowances under the CAIR NOx ozone season trading program to Michigan EGUs and Michigan non-EGUs, as well as to units that are CAIR NOx ozone season units under 40 CFR 97.304. Consequently, Michigan needs to define "new" Michigan non-EGU and "existing" Michigan non-EGU, which terminology is used in allocating allowances under that trading program. In addition, the definition in 336.1803(d) should be clarified to read as follows:

> "'Electric generating unit' or 'EGU' means, for purposes of the CAIR NOx ozone season trading program, a CAIR NOx ozone season unit under 40 CFR 97.304, a Michigan EGU for purposes of the CAIR NOx annual trading program, a CAIR NOx unit under 40 CFR 97.104."

EPA also suggests that, for clarity, Michigan should consistently define and use either the term "Michigan non-EGU" or the term "non-EGU" in the regulations. Similarly, EPA suggests that Michigan use consistent terminology when referring to "an existing EGU", "a new EGU" (rather than also referring to it as, e.g., "a new EGU CAIR NOx ozone season unit") and to "newly affected EGU" (rather than also referring to it as, e.g., "a newly-affected CAIR NOx ozone season EGU").

336.1803(3)(f) – This definition needs to apply for purposes of determining the applicability of the rule to Michigan EGUs , as well as Michigan non-EGUs.

336.1803(3)(h) –Michigan needs to revise this definition to incorporate the applicability language for electric generating units in Michigan's NOx SIP Call rule. In expanding the applicability provisions of EPA's CAIR NOx ozone season model rule to include all units included in Michigan's NOx SIP Call trading program, Michigan's rule must cover all units that are exempt under the CAIR FIP (e.g., certain cogeneration units) but that are subject to Michigan's NOx SIP Call rule. See 40 CFR 51.121(ee)(1). Consequently, "Michigan EGUs" needs to be defined as units that are not CAIR NOx ozone season units under 40 CFR 97.304 and:

> "(i) For units in the Michigan fine grid zone that commenced operation before January 1, 1997, a unit serving a generator during 1995 or 1996 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale.

"(ii) For units in the Michigan fine grid zone that commenced operation on or after January 1, 1997 and before January 1, 1999, a unit serving a generator during 1997 or 1998 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale.
"(iii) For units in the Michigan fine gird zone that commence operation on or after January 1, 1999, a unit serving a generator at any time that has a nameplate capacity of more than 25 megawatts and produces electricity for sale."

In addition, Michigan needs to add a statement in the definition that, for purposes of this definition, the term "unit" is defined as set forth in Michigan's NOx SIP Call rule.

336.1803(3)(j) – Michigan needs to revise this definition to: limit the units involved to those that are in the Michigan fine grid zone and are not CAIR NOx ozone season units under 40 CFR 97.304. 4In addition, Michigan needs to add a statement in the definition that, for purposes of this definition, the term "unit" is defined as set forth in Michigan's NOx SIP Call rule.
336.1821(1)(a) -- Remove the word "Annual" . Part 97 defines "CAIR NOx units" as those subject to the annual CAIR NOx trading program. In addition, the reference to 40 CFR part 97 should be changed to refer to 40 CFR 97.104.

336.1821(1)(b) -- Change the phrase "Ozone season CAIR NOx units" to read "CAIR NOx ozone season units" to be consistent with part 97 definitions. In addition, the reference to 40 CFR part 97 should be changed to refer to 40 CFR 97.304. Also, change reference to 40 CFR 96.304 to refer to 40 CFR 97.304.

336.1821(2) -- This provision should refer to a Michigan source subject to the requirements of 336.1821(a) or (b), not 40 CFR 97.104 or 97.304, in order to include the Michigan EGUs and Michigan non-EGUs not covered under the CAIR NOx ozone season model rule.

336.1821(3) – This provision exempts from the CAIR NOx annual and ozone season trading programs any Michigan EGU that stops burning fossil fuel after January 1, 2008 for the production of electricity. Under 40 CFR 51.123(o)(2) and (p) and (aa)(2) and (ee), Michigan cannot make this change in the applicability provisions in the EPA model trading rules and the CAIR FIP and still participate in the EPA-administered trading programs. The exemption provision in 1821(3) must be removed.

336.1821(4) – It is unclear to what units these provisions on fuel adjusted allocations apply. For example, it is unclear whether Michigan intends that the provisions apply to Michigan non-EGUs and what is intended by the reference to "cogeneration unit", which term is not defined.

336.1821(5) – It seems that these provisions should apply to Michigan EGUs and Michigan non-EGUs, as well as to CAIR NOx ozone season units.

336.1821(7) – It is unclear why 40 CFR 96.30 and 96.31 (relating to compliance certifications) are referenced. It seems that 40 CFR 96.54 (addressing deductions for excess emissions) should be referenced instead. In addition, the provision should state that the deductions should be from 2009 "CAIR NOx ozone season allowances".

336.1822(3)(a) – The phrase "A 3-year allocation that is 3 years in advance of the ozone season control period" needs to be revised to read "A 3-year allocation that is 3 years in advance of the 2010 ozone season and 4 years in advance of each subsequent ozone season control period". The dates in 336.1822(3)(a) (ii) and (iii) are correct, but they are generally 4 years in advance. For example, the allocation made on April 30, 2007 is for the 2010 ozone season, which is in the year 3 years after 2007, and for the 2011 ozone season, which is in the year 4 years after 2007.

336.1822(6) – EPA suggests that the phrase "single highest heat input" be revised to read "single highest ozone season heat input".
336.1823(4)(a) – EPA suggests that Michigan clarify its rule to indicate whether a separate request must be submitted for each year for which new unit allowances are sought.

336.1823(4)(b) – EPA notes that Michigan's rule does not define "maximum design capacity". EPA suggests that, for clarity, a definition should be added. For example, Michigan's rule does not state whether the units of measure for maximum design capacity are in Megawatts steam or Megawatts electricity. The rule also does not state whether the output values (MWh) are gross or net values. In 336.1823(4)(c), the rule seems to limit MWh to electricity, but does not specify gross or net.

336.1824(2)(a) – Michigan does not have any allowances available for allocation for 2009 through the hardship set-aside. Consequently, Michigan needs to add the following at the end of the first sentence of 336.1824(2)(a): "starting in 2010".

336.1824(2)(c)(i) – EPA suggests that the phrase "single highest heat input" be revised to read "single highest ozone season heat input".

336.1824(2)(c)(iii) -- The phrase "a 3-year allocation that is 3 years in advance of the ozone season control period" needs to be revised to read "a 3-year allocation that is 3 years in advance of the 2010 ozone season and 4 years in advance of each subsequent ozone season control period".

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336.1825(1) -- Michigan does not have any allowances available for allocation for 2009 through the renewable set-aside. Consequently, Michigan needs to add the following at the end of the first sentence of 336.1825(1): "starting in 2010".

336.1825(3)(b) – EPA notes that Michigan's rule does not define "maximum design capacity". EPA suggests that, for clarity, a definition should be added. For example, Michigan's rule does not state whether the units of measure for maximum design capacity are in Megawatts steam or Megawatts electricity. The rule also does not state whether the output values (MWh) are gross or net values. In 336.1825(3)(c), the rule seems to limit MWh to electricity, but does not specify gross or net.

336.1830(2) -- The phrase "A 3-year allocation that is 3 years in advance of the ozone season control period" needs to be revised to read "A 3-year allocation that is 2 and 3 years in advance of the 2009 and 2010 ozone seasons respectively and 4 years in advance of each subsequent ozone season control period". The dates in 336.1830(2)(b) and (c) are correct, but they are generally 4 years in advance. For example, the allocation made on April 30, 2007 is for the 2009 and 2010 ozone seasons, which are in the years 2 and 3 years after 2007, and for the 2011 ozone season, which is in the year 4 years after 2007.

336.1831(2)(a) – EPA suggests that Michigan clarify its rule to indicate whether a separate request must be submitted for each year for which new unit allowances are sought.

336.1831(2)(b) -- EPA notes that Michigan's rule does not define "maximum design capacity". EPA suggests that, for clarity, a definition should be added. For example, Michigan's rule does not state whether the units of measure for maximum design capacity are in Megawatts steam or Megawatts electricity. The rule also does not state whether the output values (MWh) are gross or net values. In 336.1831(2)(c), the rule seems to limit MWh to electricity, but does not specify gross or net.

336.1832(2)(c)(iii) -- The phrase "a 3-year allocation that is 3 years in advance of the ozone season control period" needs to be revised to read "a 3-year allocation that is 2 and 3 years in advance of the 2009 and 2010 ozone seasons respectively and 4 years in advance of each subsequent ozone season control period".

336.1833(3)(b) – Michigan's compliance supplement pool provisions need some clarification in order to be consistent with 40 CFR 51.123(e)(4)(iii)(B)(2). 336.1833(3)(b)(i) should be revised to read "A showing that it would not be possible for the owners and operators of the unit to obtain sufficient amounts of electricity from other electric generation facilities, during the installation of control technology at the unit for compliance with the CAIR NOx emissions limitation, to prevent such undue risk." Similarly, 336.1833(3)(b)(ii) should be revised to read "A showing that it would not be possible for the owners and operators of the unit to obtain sufficient allowances under subrule (2) or from other sources or persons to prevent such undue risk."

we energies

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Kristine M. Krause, P.E.
Vice President - Environmental

SUBMITTED ELECTRONICALLY

April 2, 2007

Ms. Teresa Walker
Michigan Department of Environmental Quality
Air Quality Division

RE: Comments on Michigan Department of Environmental Quality Proposed Revisions to Part 8, Emission Limitations and Prohibitions-Oxides of Nitrogen; R 336.1802a, R 336.1803, R 336.1821 to R 336.1826, and R 336.1830 to R 336.1834 (SOAHR No. 2005-037EQ)

Dear Ms. Walker:

By this letter, Wisconsin Electric Power Company, doing business as We Energies ("We Energies" or "the company") is providing comments on the proposed Michigan Department of Environmental Quality (MDEQ) administrative rules for implementing the federal Clean Air Interstate Rule (CAIR). We Energies owns and operates the nine unit Presque Isle Power Plant (PIPP), which is situated near Marquette in the Upper Peninsula of Michigan.

We Energies is the principal utility subsidiary of Wisconsin Energy Corporation. The company is based in Milwaukee, Wisconsin, and serves more than 1.1 million electric customers in Wisconsin and Michigan's Upper Peninsula and more than one million natural gas customers in Wisconsin.

We have been participating in the CAIR Workgroup and appreciate the opportunity to provide input during the development of this important rule. We have brief comments on four topics:

1. MDEQ's decision to participate in the U.S. Environmental Protection Agency's (U.S.EPA) CAIR emission trading program
2. Recently proposed CAIR NOx allowance updates
3. Creation of a set-aside pool for newly affected electric generating units (EGUs)
4. Applicability language for MDEQ Part 8 rules

Michigan's Participation in U.S.EPA's CAIR Emission Trading Program

We support MDEQ's proposal to participate in U.S.EPA's CAIR emission trading program. We Energies owns and operates EGUs in both Michigan's Upper Peninsula and in Southeast Wisconsin. MDEQ participation in the federal trading program will allow the company to make cost-effective emission reductions over its generation system. In addition, having the option of purchasing emission allowances to supplement unforeseen shortfalls is also a valuable complement to the company's proactive emission reduction plan.

Opting into the U.S.EPA's emission trading program also offers tangible benefits in terms of streamlining air quality programs and regulatory requirements. Participating in the federal program offers an administrative savings to MDEQ since U.S.EPA would administer all of the emissions tracking, reporting, and verification functions. Participating in the federal program provides streamlined regulatory requirements for affected sources. States that opt into the federal program facilitate a consistent program structure and consistent compliance requirements for utilities like We Energies doing business in multiple states. This reduces the utility staff time necessary to comply with program administrative tasks, and allows companies to more easily incorporate compliance activities into their environmental management systems and standardize emissions software and databases.

Recently Proposed CAIR NOx Allowance Updates

We understand that there has been a recent proposal to calculate allowances under the CAIR NOx programs based on the data that resides within U.S.EPA's Clean Air Markets Division's database. MDEQ is in the process of reviewing the NOx allocation data and updating the CAIR spreadsheets. We concur with these revisions but request that they do not delay this important rule-making process.

Creation of a set-aside Pool for Newly Affected EGUs

We support MDEQ's proposal to establish a set-aside pool for 2009 ozone season allocations. These allocations would be available for newly affected EGUs that were not part of the ozone "SIP Call". The pool is established based on ozone season allowances that have been carried over from the federal NOx SIP call budget. The company's affected units under the CAIR rule were not part of the NOx SIP call due to their geographic location, so were not allocated any ozone season allocations as part of U.S.EPA's CAIR program. We appreciate the opportunity for access to ozone season allocations from the set-aside pool, and MDEQ's recognition of the need for equity among CAIR-affected sources.

Applicability Language for MDEQ Part 8 Rules

We Energies Presque Isle units are currently subject to *Part 8, Emission Limitations and Prohibitions--Oxides of Nitrogen, R 336.1801 Emission of oxides of nitrogen from non-sip call stationary sources*. We interpret the provisions in rule 801 to be that once our units are subject to the MDEQ implementation of the CAIR (Rules 802a-834), then they are no longer subject to Rule 801. If this is an incorrect interpretation we would appreciate clarification.

We agree with transitioning away from Rule 801 and complying with CAIR. We would disagree with the applicability of both rules, and would request rule language stating single rule applicability.

This concludes the comments on behalf of We Energies. Thank you for considering these comments on provisions for implementing the federal CAIR program. Please contact me at (414) 221-2443, or Kris McKinney, who has been our company's participant in the CAIR Rules Workgroup, at (414) 221-2157 if you have any questions regarding our rule comments.

Sincerely,

Kristine M. Krause

Kristine M. Krause, P.E.
Vice President-Environmental

cc: Vince Hellwig, Chief, Air Quality Division, MDEQ
Steve Chester, Director, MDEQ

APPENDIX A

Summary of Proposed Rules

SOAHR 2005-037EQ

MICHIGAN DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

PROPOSED AMENDMENTS TO AIR POLLUTION CONTROL RULES
SOAHR 2005-037EQ

SUBJECT

A public hearing will be held on April 2, 2007, on proposed administrative rules promulgated pursuant to Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (Act 451); Part 8. Emission Limitations and Prohibitions—Oxides of Nitrogen; R 336.1802a, R 336.1803, R 336.1821 to R 336.1826, and R 336.1830 to R 336.1834.

PURPOSE FOR THE PROPOSED RULES AND BACKGROUND

These rules are being developed to meet requirements of the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR) to reduce transported emissions of oxides of nitrogen (NOx) from electric generating units (EGUs) and large non-electric generating units. The rules will be submitted to the EPA as part of the Michigan State Implementation Plan (SIP) upon final promulgation.

The federal CAIR program requires the state to develop the regulations to reduce NOx emissions. The proposed rules will result in reduced NOx emissions from EGUs and large non-EGUs, which will help reduce the formation of particulate matter less than 2.5 microns in diameter and ground-level ozone in Michigan and downwind areas. The Department of Environmental Quality (DEQ) worked with a number of stakeholders to develop and adopt these rules. The workgroup included representatives from various industrial, commercial, small business, consumer and environmental groups and associations. The workgroup met several times during 2005 and 2006.

SUMMARY OF THE PROPOSED RULES

Rules 802a, 803, 821 through 826, and 830 through 834 are based on the EPA CAIR rules, a NOx emissions cap and trade system to be administered by the EPA.

- Rule 802a contains adoption by reference language.
- Rule 803 modifies the existing definitions to address the CAIR requirements.
- Rule 821 contains applicability criteria.

- Rule 822 establishes the NOx budgets for the ozone season control period and establishes the allocation methodology procedures for the ozone season. See the attached spreadsheets for the allocation tables for each group.
- Rule 823 establishes the provisions for a new source set-aside ozone season control period allocation pool for new EGUs, new non-EGUS, and newly affected EGUS (which were not included in the original NOx program due to geographic location).
- Rule 824 establishes the provisions for a hardship set-aside ozone season control period allocation pool to address issues for small businesses that are impacted by the rules.
- Rule 825 establishes the provisions for a renewable set-aside ozone season control period allocation pool to encourage the use of renewable energy in the production of electricity in the state.
- Rule 826 adopts by reference the ozone season control period opt-in provisions under the federal CAIR rules.
- Rule 830 establishes the NOx budgets for the annual control period and establishes the allocation methodology procedures for the annual control period. See the attached spreadsheets for the allocation tables for each group.
- Rule 831 establishes the provisions for a new source set-aside annual control period allocation pool for new EGUs.
- Rule 832 establishes the provisions for a hardship set-aside annual control period allocation pool to address issues for small businesses that are impacted by the rules.
- Rule 833 establishes the provisions for an annual control period compliance supplement pool with early reduction credit generation and hardship provisions for the newly affected EGUs that were not in the original NOx Budget Program and are adversely impacted by this new program for 2009.
- Rule 834 adopts by reference the opt-in provisions for the annual control period under the federal CAIR rules.

ISSUES FOR COMMENT

A number of key issues have been raised by EPA following the last workgroup meeting. The issues are listed below, along with DEQ's proposed response. Comment is requested in particular on these areas of the proposed rules.

1. The EPA raised concerns about the excess in Michigan's 2009 budget for the ozone season. EPA stated: "The sum of these two amounts is 31,247, which exceeds Michigan's budget for 2009 of 31,180 by 67 allowances. The allowances available in the set-aside for 2009 must be reduced by 67 allowances in order to adhere to Michigan's budget." The DEQ revised the rule, reducing the 2009 budget by 67 allowances.

2. The EPA stated that: "states cannot change the opt-in provisions except to choose whether to allow non-repowering units, repowering units, or both types of units to opt-in.

Particularly since the Michigan rule allows both types of units to opt-in, Michigan should adopt by reference EPA's opt-in provisions." The DEQ revised the rule, adopting by reference the opt-in provisions under EPA's model CAIR rule and removing the wording used in the draft rules.

3. The EPA stated: "in order to ensure that all units covered by the Michigan NOx Budget Trading Program, and not by the CAIR applicability provisions, are brought into the Michigan's CAIR NOx ozone season trading program, Michigan's draft rule needs to revise the CAIR applicability provisions …" The DEQ revised the applicability and definition portions of the rules to address these EPA concerns.

4. The EPA changed the compliance date from 2010 to 2009 and utilized the NOx Budget allowances from the NOx SIP Call for the 2009 ozone season. This resulted in no allocations being available for the coarse grid utility sources during the ozone season of 2009. The DEQ revised the rules to allow affected sources to request allowances from the new source set-aside for the 2009 ozone season and give these sources the opportunity to request additional "hardship" allowances from the Annual Compliance Supplement Pool for 2009.

5. One issue has never been resolved with EPA regarding Michigan's budgets: The EPA included Michigan's biomass units in the program without including their heat input values in the determination of the budgets. This is still not resolved after repeated correspondence with the EPA's Clean Air Market Division. After consultation with the affected biomass facilities, DEQ has agreed to exempt any biomass units that restrict their fuel usage to biomass only (eliminating all fossil fuels) by January 1, 2008.
Rules 803 and 821 have been revised to address this.

ACTIONS FOLLOWING THE PUBLIC HEARING

Following the public hearing, the Air Quality Division staff will review the comments received and make appropriate changes to the proposed rules. The proposed rule package will then be submitted to the State Office of Administrative Hearings and Rules, the Legislative Service Bureau, and the Joint Committee on Administrative Rules as prescribed by the Administrative Procedures Act, 1969 PA 306, as amended. The rules will go into effect immediately after filing with the Secretary of State's office. The final rules will be submitted to the EPA as a SIP revision.

Prepared by: Teresa Walker
Attachments
February 7, 2007

Michigan Non EGUs Ozone Season

Company Name	SRN	Unit ID	Name Plate Capacity in mmBtu	County	Emission Factor	2001 Heat Input	2002 Heat Input	2003 Heat Input	2004 Heat Input	2005 Heat Input	Highest 2 year ave.	CAIR Allow	Adjusted CAIR 2010	Corrected (Rounding) CAIR 2010	Corrected (Rounding) CAIR 2011
CE - Karn_Weadock	B2840	A	300	Bay	0.17	61,855	27,750	23,859	24,640	47,738	54,797	5	9	9	9
CE - Karn_Weadock	B2840	B	300	Bay	0.17	77,086	54,657	20,570	29,235	60,886	68,986	6	12	12	12
Dearborn Ind. Gen.	N6631	GT21	1562	Wayne	**0.03**	2,956,150	3,849,500	755,800	1,978,000	1,700,445	3,402,825	56	112	112	112
Dearborn Ind. Gen.	N6631	GT31	1562	Wayne	**0.03**	2,560,600	2,855,100	1,075,300	1,544,800	1,950,156	2,707,850	45	89	89	89
Dow Chemical USA	A4033	0401	300	Midland	0.17	8,100	21,935	4,755	2,728	1,362	15,017	1	3	5	5
Dow Chemical USA	A4033	0402	300	Midland	0.17	7,115	21,626	3,428	3,418	1,357	14,370	1	2	4	4
Graphics Pkg.	B1678	0003	253	Kalamazoo	0.17	753,521	462,844	753,095	642,279	630,034	753,308	64	128	128	128
Lansing BW&L	B2647	0014	290	Ingham	0.17	345,726	20,554	0	0	0	183,140	16	31	31	31
Menasha Corp	A0023	0024	294	Allegan	0.17	511,728	461,675	523,686	514,186	333,643	518,936	44	88	88	88
Menasha Corp	A0023	0025	294	Allegan	0.17	530,507	490,743	534,494	506,831	330,777	532,501	45	91	90	90
MSU	K3249	0053	300	Ingham	0.17	637,673	621,598	599,293	407,107	836,889	737,281	63	126	125	125
MSU	K3249	0054	300	Ingham	0.17	503,492	543,773	532,129	555,702	634,413	595,058	51	101	101	101
MSU	K3249	0055	452	Ingham	0.17	540,050	789,106	699,677	784,297	935,858	862,482	73	147	147	147
MSU	K3249	0056	433	Ingham	0.17	755,606	649,942	1,059,065	713,930	576,236	907,335	77	154	154	154
U of M	M0675	003	315	Washtenaw	0.17	233,845	152,103	141,133	338,819	509,756	424,288	36	72	72	72
U of M	M0675	004	315	Washtenaw	0.17	239,971	168,956	469,248	201,498	516,962	493,105	42	84	84	84
U of M	M0675	006	358	Washtenaw	**0.10**	94,187	508,152	350,087	657,491	130,943	582,822	29	58	58	58
												654	**1,309**	**1,309**	**1,309**

	Source information								Annual Values				Calculations					
Company Name	Plant Name	Unit ID	Fuel Type	Permit Limit (*if appropriate)	Emission Factor 2010-2014	Fuel Adj Factor	Arithmetic average	2001 Heat Input	2002 Heat Input	2003 Heat Input	2004 Heat Input	2005 Heat Input	Highest 2 year average	Calc'd CAIR	Adjusted 2010 CAIR	Corrected (Rounding) 2009	Corrected (Rounding) 2010	Corrected (Rounding) 2011
CMS Gen/MI Pwr	Kalamazoo River	1	gas	**0.085**	0.15	0.40	**0.07**	16,152	11,848	23,428	68,053	164,297	116,175	4	4	4	4	4
CMS Gen/MI Pwr	Livingston Station	001	gas		0.15	0.40		36,696	11,166	22,625	17,607	97,869	67,283	2	2	2	2	2
CMS Gen/MI Pwr	Livingston Station	002	gas		0.15	0.40		34,566	11,962	25,673	16,444	91,409	62,988	2	2	2	2	2
CMS Gen/MI Pwr	Livingston Station	003	gas		0.15	0.40		34,042	14,775	21,765	7,904	112,306	73,174	2	2	2	2	2
CMS Gen/MI Pwr	Livingston Station	004	gas		0.15	0.40		35,690	9,249	21,530	16,698	91,463	63,577	2	2	2	2	2
CMS Generation	TES Filer City	B1	solid		0.15	1.00		2,731,978	2,695,191	2,782,690	3,151,616	2,879,646	3,015,631	226	221	221	221	221
CMS Generation	TES Filer City	B2	solid		0.15	1.00		2,731,978	2,695,191	2,782,690	3,151,616	2,879,646	3,015,631	226	221	221	221	221
Consumers Energy	Campbell	1	solid		0.15	1.00		13,155,517	13,155,517	21,798,697	21,367,302	19,732,030	21,583,000	1,619	1,581	1,581	1,581	1,581
Consumers Energy	Campbell	2	solid		0.15	1.00		24,125,827	24,125,827	24,312,028	22,594,539	21,102,965	24,218,928	1,816	1,774	1,774	1,774	1,774
Consumers Energy	Campbell	3	solid		0.15	1.00		62,570,086	62,570,086	53,055,997	67,055,963	55,140,163	64,813,025	4,861	4,748	4,747	4,747	4,747
Consumers Energy	Cobb	1	gas		0.15	0.40		278,874	278,874	185,467	47,190	295	278,874	8	8	8	8	8
Consumers Energy	Cobb	2	gas		0.15	0.40		255,344	255,344	169,559	47,935	227	255,344	8	7	7	7	7
Consumers Energy	Cobb	3	gas		0.15	0.40		306,620	306,620	190,193	7,820	133	306,620	9	9	9	9	9
Consumers Energy	Cobb	4	solid		0.15	1.00		12,357,348	12,357,348	11,352,929	11,950,163	11,677,146	12,357,348	927	905	905	905	905
Consumers Energy	Cobb	5	solid		0.15	1.00		10,219,548	10,219,548	12,591,560	11,499,723	11,527,460	12,059,510	904	883	883	883	883
Consumers Energy	Karn	1	solid		0.15	1.00		17,877,384	17,877,384	18,511,275	19,068,898	15,836,937	18,790,087	1,409	1,376	1,376	1,376	1,376
Consumers Energy	Karn	2	solid		0.15	1.00		20,219,624	20,219,624	20,039,578	16,067,341	20,141,106	20,219,624	1,516	1,481	1,481	1,481	1,481
Consumers Energy	Karn	3	gas		0.15	0.40		7,771,450	7,771,450	6,915,250	3,361,613	2,984,763	7,771,450	233	228	228	228	228
Consumers Energy	Karn	4	gas		0.15	0.40		6,763,915	6,763,915	4,786,746	2,576,621	1,124,380	6,763,915	203	198	198	198	198
Consumers Energy	Thetford CT	1	gas		0.15	0.40		21,687	21,687	18,836	19,255	8,062	21,687	1	1	1	1	1
Consumers Energy	Thetford CT	2	gas		0.15	0.40		21,687	21,687	18,836	19,255	8,062	21,687	1	1	1	1	1
Consumers Energy	Thetford CT	3	gas		0.15	0.40		21,687	21,687	18,836	19,255	8,062	21,687	1	1	1	1	1
Consumers Energy	Thetford CT	4	gas		0.15	0.40		21,687	21,687	18,836	19,255	8,062	21,687	1	1	1	1	1
Consumers Energy	Weadock	7	solid		0.15	1.00		10,420,490	10,420,490	12,239,672	12,822,427	9,132,977	12,531,050	940	918	918	918	918
Consumers Energy	Weadock	8	solid		0.15	1.00		14,062,399	14,062,399	11,622,625	12,692,967	12,303,429	14,062,399	1,055	1,030	1,030	1,030	1,030
Consumers Energy	Whiting	1	solid		0.15	1.00		7,539,106	7,539,106	8,907,503	8,924,762	8,555,544	8,916,133	669	653	653	653	653
Consumers Energy	Whiting	2	solid		0.15	1.00		8,759,753	8,759,753	7,879,230	8,503,714	8,571,610	8,759,753	657	642	642	642	642
Consumers Energy	Whiting	3	solid		0.15	1.00		9,101,039	9,101,039	10,278,867	9,926,144	10,715,793	10,497,330	787	769	769	769	769
Covert Generating LLC	Covert	1	gas		0.15	0.40		0	0	1,872,811	632,296	1,934,155	1,903,483	57	56	56	56	56
Covert Generating LLC	Covert	2	gas		0.15	0.40		0	0	5,295,970	747,297	2,114,060	3,705,015	111	109	109	109	109
Covert Generating LLC	Covert	3	gas		0.15	0.40		0	0	0	1,854,637	2,583,525	2,219,081	67	65	65	65	65
Dearborn Ind. Gen.	Dearborn Ind.	B1	gas	**0.1**	0.15	0.40	**0.08**	806,355	2,437,348	2,504,066	2,890,126	3,644,590	3,267,358	131	128	128	128	128
Dearborn Ind. Gen.	Dearborn Ind.	B2	gas	**0.1**	0.15	0.40	**0.08**	697,601	2,142,750	2,785,766	2,398,019	3,451,792	3,118,779	125	122	122	122	122
Dearborn Ind. Gen.	Dearborn Ind.	B3	gas	**0.1**	0.15	0.40	**0.08**	628,487	2,654,975	2,510,858	2,895,188	3,682,266	3,288,727	132	128	128	128	128
Dearborn Ind. Gen.	Dearborn Ind.	GTP1	gas	**0.033**	0.15	0.40	**0.05**	450,274	595,935	67,936	203,263	1,951,533	1,273,734	30	29	29	29	29
Detroit Edison	Belle River	1	solid		0.15	1.00		52,284,748	55,238,546	39,503,328	47,984,884	43,592,569	53,761,647	4,032	3,938	3,937	3,937	3,937
Detroit Edison	Belle River	2	solid		0.15	1.00		50,693,844	32,606,529	48,243,589	48,332,027	50,500,914	50,597,379	3,795	3,706	3,706	3,706	3,706
Detroit Edison	Belle River	CTG121	gas	**0.05**	0.15	0.40	**0.06**	562,428	858,536	401,816	197,046	617,886	738,211	20	20	20	20	20
Detroit Edison	Belle River	CTG122	gas	**0.05**	0.15	0.40	**0.06**	401,119	661,034	286,576	137,252	608,169	634,602	17	17	17	17	17
Detroit Edison	Belle River	CTG131	gas	**0.05**	0.15	0.40	**0.06**	403,326	580,541	302,417	120,636	605,990	593,266	16	16	16	16	16
Detroit Edison	Connors Creek	15	gas		0.15	0.40		264,972	260,081	102,378	146,630	389,921	327,447	10	10	10	10	10
Detroit Edison	Connors Creek	16	gas		0.15	0.40		276,197	220,549	74,398	105,008	317,876	297,037	9	9	9	9	9
Detroit Edison	Connors Creek	17	gas		0.15	0.40		236,651	146,908	99,776	143,831	282,956	259,804	8	8	8	8	8
Detroit Edison	Connors Creek	18	gas		0.15	0.40		265,491	203,715	83,168	131,985	326,422	295,957	9	9	9	9	9
Detroit Edison	Delray	CTG111	gas	**0.08**	0.15	0.40	**0.07**	206,339	397,717	233,605	152,365	344,895	371,306	13	13	13	13	13
Detroit Edison	Delray	CTG121	gas	**0.08**	0.15	0.40	**0.07**	182,261	383,730	207,170	183,282	414,814	399,272	14	14	14	14	14
Detroit Edison	East China	1	gas	**0.1**	0.15	0.40	**0.08**	112,328	66,874	112,328	0	265,296	188,812	8	7	7	7	7
Detroit Edison	East China	2	gas	**0.1**	0.15	0.40	**0.08**	93,866	67,435	93,866	0	272,179	183,023	7	7	7	7	7
Detroit Edison	East China	3	gas	**0.1**	0.15	0.40	**0.08**	91,329	85,737	91,329	0	293,094	192,212	8	8	8	8	8
Detroit Edison	East China	4	gas	**0.1**	0.15	0.40	**0.08**	105,886	62,263	105,886	0	267,345	186,616	7	7	7	7	7
Detroit Edison	Greenwood	1	gas/oil		0.15	0.40		9,673,911	11,701,703	6,969,328	5,501,890	7,927,441	10,687,807	321	313	313	313	313
Detroit Edison	Greenwood	CTG111	gas	**0.05**	0.15	0.40	**0.06**	438,076	606,876	203,477	24,408	542,453	574,665	16	15	15	15	15
Detroit Edison	Greenwood	CTG112	gas	**0.05**	0.15	0.40	**0.06**	320,807	544,587	121,400	25,263	546,583	545,585	15	15	15	15	15
Detroit Edison	Greenwood	CTG121	gas	**0.05**	0.15	0.40	**0.06**	342,731	500,185	124,811	23,250	180,528	421,458	12	11	11	11	11
Detroit Edison	Hancock	12-1 (5)	gas		0.15	0.40		58,068	27,962	51,901	6,585	19,770	54,985	2	2	2	2	2
Detroit Edison	Hancock	12-2 (6)	gas		0.15	0.40		47,967	29,623	51,516	6,108	6,185	49,742	1	1	1	1	1
Detroit Edison	Harbor Beach	1	solid		0.15	1.00		2,283,416	2,737,110	2,291,301	2,525,983	3,805,441	3,271,276	245	240	240	240	240
Detroit Edison	Marysville	9	solid		0.15	1.00		508,369	0	0	0	0	254,185	19	19	19	19	19
Detroit Edison	Marysville	10	solid		0.15	1.00		406,858	0	0	0	0	203,429	15	15	15	15	15
Detroit Edison	Marysville	11	solid		0.15	1.00		431,617	0	0	0	0	215,809	16	16	16	16	16
Detroit Edison	Marysville	12	solid		0.15	1.00		517,072	0	0	0	0	258,536	19	19	19	19	19
Detroit Edison	Monroe	1	solid		0.15	1.00		31,787,540	37,900,714	36,375,042	41,328,125	44,433,797	42,880,961	3,216	3,141	3,141	3,141	3,141
Detroit Edison	Monroe	2	solid		0.15	1.00		40,137,687	44,583,407	34,080,756	39,069,142	37,320,815	42,360,547	3,177	3,103	3,103	3,103	3,103
Detroit Edison	Monroe	3	solid		0.15	1.00		48,668,710	43,377,986	43,799,958	28,379,861	46,055,494	47,362,102	3,552	3,469	3,469	3,469	3,469
Detroit Edison	Monroe	4	solid		0.15	1.00		50,570,249	32,484,566	54,468,862	49,753,246	48,732,751	52,519,556	3,939	3,847	3,847	3,847	3,847
Detroit Edison	River Rouge	1	gas		0.15	0.40		736,582	551,706	253,472	18,092	58,024	644,144	19	19	19	19	19
Detroit Edison	River Rouge	2	solid		0.15	1.00		9,345,293	18,528,487	15,109,969	17,182,775	15,915,215	17,855,631	1,339	1,308	1,308	1,308	1,308
Detroit Edison	River Rouge	3	solid		0.15	1.00		15,960,363	15,942,526	13,589,912	17,245,981	12,365,866	16,603,172	1,245	1,216	1,216	1,216	1,216
Detroit Edison	St. Clair	1	solid		0.15	1.00		8,487,866	9,079,111	7,546,331	9,024,092	8,297,906	9,051,602	679	663	663	663	663
Detroit Edison	St. Clair	2	solid		0.15	1.00		9,993,402	5,359,011	4,186,273	9,145,258	8,434,530	9,569,330	718	701	701	701	701

	Source information							Annual Values					Calculations					
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (*if appropriate)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arithmetic average**	**2001 Heat Input**	**2002 Heat Input**	**2003 Heat Input**	**2004 Heat Input**	**2005 Heat Input**	**Highest 2 year average**	**Calc'd CAIR**	**Adjusted 2010 CAIR**	**Corrected (Rounding) 2009**	**Corrected (Rounding) 2010**	**Corrected (Rounding) 2011**
Detroit Edison	St. Clair	3	solid		0.15	1.00		7,933,356	9,311,953	8,893,199	7,040,417	8,209,177	9,102,576	683	667	667	667	667
Detroit Edison	St. Clair	4	solid		0.15	1.00		8,484,952	9,604,698	8,873,194	7,241,706	9,583,774	9,594,236	720	703	703	703	703
Detroit Edison	St. Clair	6	solid		0.15	1.00		17,597,973	17,415,113	14,354,894	19,239,918	17,931,580	18,585,749	1,394	1,361	1,361	1,361	1,361
Detroit Edison	St. Clair	7	solid		0.15	1.00		8,608,084	22,691,353	26,088,697	25,930,296	23,592,556	26,009,497	1,951	1,905	1,905	1,905	1,905
Detroit Edison	Trenton Channel	16	solid		0.15	1.00		4,370,089	4,332,832	4,129,572	5,155,718	4,337,513	4,762,904	357	349	349	349	349
Detroit Edison	Trenton Channel	17	solid		0.15	1.00		4,106,433	4,346,912	4,317,457	4,801,286	4,410,672	4,605,979	345	337	337	337	337
Detroit Edison	Trenton Channel	18	solid		0.15	1.00		4,331,407	4,081,311	3,731,235	4,943,592	4,027,943	4,637,500	348	340	340	340	340
Detroit Edison	Trenton Channel	19	solid		0.15	1.00		4,408,814	3,688,673	4,162,145	4,955,718	4,193,209	4,682,266	351	343	343	343	343
Detroit Edison	Trenton Channel	9A	solid		0.15	1.00		28,407,803	29,653,710	24,008,692	27,463,429	27,170,088	29,030,757	2,177	2,127	2,127	2,127	2,127
Detroit PLD	Mistersky	5	liquid		0.15	0.60		2,070,750	2,070,750	3,191,905	3,460,811		3,326,358	150	146	146	146	146
Detroit PLD	Mistersky	6	liquid		0.15	0.60		3,140,297	3,140,297	0	0		3,140,297	141	138	138	138	138
Detroit PLD	Mistersky	7	liquid		0.15	0.60		5,097,836	5,097,836	2,806,482	2,980,302		5,097,836	229	224	224	224	224
Detroit PLD	Mistersky	GT-1	gas		0.15	0.40		0	0	0	0	0	0	0	0	0	0	0
Dynegy	Renaissance	CT1	gas	**0.06**	0.15	0.40	**0.06**	0	0	841,395	273,355	554,974	698,185	21	20	20	20	20
Dynegy	Renaissance	CT2	gas	**0.06**	0.15	0.40	**0.06**	0	0	715,802	301,578	61,334	508,690	15	15	15	15	15
Dynegy	Renaissance	CT3	gas	**0.06**	0.15	0.40	**0.06**	0	0	0	232,760	89,798	161,279	5	5	5	5	5
Dynegy	Renaissance	CT4	gas	**0.06**	0.15	0.40	**0.06**	0	0	670,238	263,805	91,559	467,022	14	14	14	14	14
FirstEnergy Genco	Sumpter	1	gas	**0.1**	0.15	0.40	**0.08**	0	0	452,170	166,863	63,532	309,517	12	12	12	12	12
FirstEnergy Genco	Sumpter	2	gas	**0.1**	0.15	0.40	**0.08**	0	0	392,970	166,065	57,361	279,518	11	11	11	11	11
FirstEnergy Genco	Sumpter	3	gas	**0.1**	0.15	0.40	**0.08**	0	0	399,360	171,321	61,233	285,341	11	11	11	11	11
FirstEnergy Genco	Sumpter	4	gas	**0.1**	0.15	0.40	**0.08**	0	0	438,019	128,864	56,513	283,442	11	11	11	11	11
Grand Haven BLP	Sims	3	solid		0.15	1.00		4,365,201	2,926,603	3,964,595	3,497,186	4,576,266	4,470,734	335	327	327	327	327
Holland BPW	48th Street	7	gas		0.15	0.40		151,225	151,225	310,743	72,621	87,519	230,984	7	7	7	7	7
Holland BPW	48th Street	8	gas		0.15	0.40		47,965	47,965	97,092	57,105	8,012	77,099	2	2	2	2	2
Holland BPW	48th Street	9	gas	**0.125**	0.15	0.40	**0.09**	392,477	392,477	719,906	330,582	171,618	556,192	26	25	25	25	25
Holland BPW	De Young	5	solid		0.15	1.00		2,287,120	2,287,120	1,905,186	2,327,238	1,996,348	2,307,179	173	169	169	169	169
Kinder Morgan	Jackson Power	7EA	gas	**0.1**	0.15	0.40	**0.08**	0	1,179,993	234,816	100,155	820,208	1,000,101	40	39	39	39	39
Kinder Morgan	Jackson Power	LM1	gas	**0.1**	0.15	0.40	**0.08**	0	528,193	103,052	47,822	200,622	364,408	15	14	14	14	14
Kinder Morgan	Jackson Power	LM2	gas	**0.1**	0.15	0.40	**0.08**	0	500,189	97,160	51,947	220,776	360,483	14	14	14	14	14
Kinder Morgan	Jackson Power	LM3	gas	**0.1**	0.15	0.40	**0.08**	0	555,183	95,093	31,916	272,143	413,663	17	16	16	16	16
Kinder Morgan	Jackson Power	LM4	gas	**0.1**	0.15	0.40	**0.08**	0	557,509	90,831	44,938	203,757	380,633	15	15	15	15	15
Kinder Morgan	Jackson Power	LM5	gas	**0.1**	0.15	0.40	**0.08**	0	521,353	93,698	37,494	285,472	403,413	16	16	16	16	16
Kinder Morgan	Jackson Power	LM6	gas	**0.1**	0.15	0.40	**0.08**	0	490,988	90,771	34,750	219,895	355,442	14	14	14	14	14
Lansing BWL	Eckert Station	1	solid		0.15	1.00		1,924,208	1,924,208	2,390,490	2,735,145	2,234,063	2,562,818	192	188	188	188	188
Lansing BWL	Eckert Station	2	solid		0.15	1.00		2,037,353	2,037,353	2,200,642	1,516,592	2,786,797	2,493,719	187	183	183	183	183
Lansing BWL	Eckert Station	3	solid		0.15	1.00		1,563,005	1,563,005	3,015,535	2,491,151	2,826,199	2,920,867	219	214	214	214	214
Lansing BWL	Eckert Station	4	solid		0.15	1.00		4,556,442	4,556,442	5,455,215	5,541,742	4,850,233	5,498,479	412	403	403	403	403
Lansing BWL	Eckert Station	5	solid		0.15	1.00		4,479,508	4,479,508	4,409,146	4,689,098	5,181,326	4,935,212	370	362	362	362	362
Lansing BWL	Eckert Station	6	solid		0.15	1.00		3,973,753	3,973,753	4,498,763	5,017,954	4,918,205	4,968,080	373	364	364	364	364
Lansing BWL	Erickson	1	solid		0.15	1.00		6,132,663	6,132,663	8,726,322	9,905,670	8,880,260	9,392,965	704	688	688	688	688
Marquette. City of	Shiras	3	solid		0.15	1.00		3,897,490	3,897,490	3,551,115	3,793,129	3,387,485	3,897,490	292	286	286	286	286
Michigan Power LP	MI Power LP	G101	gas		0.15	0.40		8,154,711	8,154,711	9,602,133	10,019,901	9,796,427	9,908,164	297	290	290	290	290
Michigan Public Pwr	Kalkaska CT #1	1A	gas		0.15	0.40		0	0	0	59,696	101,115	80,406	2	2	2	2	2
Michigan Public Pwr	Kalkaska CT #1	1B	gas		0.15	0.40		0	0	0	69,686	80,530	75,108	2	2	2	2	2
Midland Cogen V.	Midland Cogen V.	GT10	gas		0.15	0.40		6,248,493	5,591,400	5,019,880	8,111,834	**3,632,000**	7,180,164	215	210	210	210	210
Midland Cogen V.	Midland Cogen V.	GT11	gas		0.15	0.40		6,871,055	5,670,918	5,174,188	8,276,253	**3,097,543**	7,573,654	227	222	222	222	222
Midland Cogen V.	Midland Cogen V.	GT12	gas	**0.14**	0.15	0.40	**0.10**	6,373,823	5,027,637	4,577,762	7,212,935	**2,351,798**	6,793,379	340	332	332	332	332
Midland Cogen V.	Midland Cogen V.	GT13	gas		0.15	0.40		7,278,544	6,070,442	5,595,108	7,474,816	**5,822,636**	7,376,680	221	216	216	216	216
Midland Cogen V.	Midland Cogen V.	GT14	gas		0.15	0.40		6,244,846	6,440,071	5,842,690	6,927,472	**6,958,488**	6,942,980	208	203	203	203	203
Midland Cogen V.	Midland Cogen V.	GT3	gas		0.15	0.40		6,265,292	7,626,419	6,212,930	8,146,665	**7,130,236**	7,886,542	237	231	231	231	231
Midland Cogen V.	Midland Cogen V.	GT4	gas		0.15	0.40		7,326,288	6,473,233	5,867,439	7,461,836	**6,000,346**	7,394,062	222	217	217	217	217
Midland Cogen V.	Midland Cogen V.	GT5	gas		0.15	0.40		5,643,725	6,229,356	5,658,507	6,981,125	**5,120,373**	6,605,241	198	194	194	194	194
Midland Cogen V.	Midland Cogen V.	GT6	gas		0.15	0.40		5,759,330	6,916,087	6,245,468	7,300,661	**6,524,064**	7,108,374	213	208	208	208	208
Midland Cogen V.	Midland Cogen V.	GT7	gas		0.15	0.40		6,640,841	5,807,441	5,366,555	8,335,206	**4,839,798**	7,488,024	225	219	219	219	219
Midland Cogen V.	Midland Cogen V.	GT8	gas		0.15	0.40		7,667,023	6,480,616	5,815,477	8,290,856	**3,462,938**	7,978,940	239	234	234	234	234
Midland Cogen V.	Midland Cogen V.	GT9	gas		0.15	0.40		6,670,350	5,982,573	5,108,127	7,879,375	**3,706,338**	7,274,863	218	213	213	213	213
Mirant Zeeland	Zeeland Power	1	gas	**0.04**	0.15	0.40	**0.05**	715,822	715,822	512,685	116,802	21,509	715,822	18	17	17	17	17
Mirant Zeeland	Zeeland Power	2	gas	**0.04**	0.15	0.40	**0.05**	612,469	612,469	544,688	120,033	46,340	612,469	15	15	15	15	15
Mirant Zeeland	Zeeland Power	3	gas	**0.13**	0.15	0.40	**0.10**	0	0	1,318,948	1,282,492	777,561	1,300,720	62	60	60	60	60
Mirant Zeeland	Zeeland Power	4	gas	**0.13**	0.15	0.40	**0.10**	0	0	1,131,993	1,170,521	564,349	1,151,257	55	53	53	53	53
MSCPA	Enidcott Gen St	1	solid		0.15	1.00		4,552,864	4,552,864	4,707,733	5,416,635	5,447,333	5,431,984	407	398	398	398	398
WE Energies	Presque Isle	2	solid		0.15	1.00		794,225	794,225	47,951	434,231	437,119	794,225	60	58	58	58	58
WE Energies	Presque Isle	3	solid		0.15	1.00		3,207,036	3,207,036	3,564,883	3,200,684	3,714,505	3,639,694	273	267	267	267	267
WE Energies	Presque Isle	4	solid		0.15	1.00		4,023,701	4,023,701	2,857,953	3,843,771	4,007,906	4,023,701	302	295	295	295	295
WE Energies	Presque Isle	5	solid		0.15	1.00		5,506,259	5,506,259	6,084,422	4,214,514	5,700,616	5,892,519	442	432	432	432	432
WE Energies	Presque Isle	6	solid		0.15	1.00		6,479,197	6,479,197	5,194,678	5,527,597	5,437,202	6,479,197	486	475	475	475	475
WE Energies	Presque Isle	7	solid		0.15	1.00		6,275,974	6,275,974	6,288,693	6,381,584	5,506,929	6,335,139	475	464	464	464	464
WE Energies	Presque Isle	8	solid		0.15	1.00		6,179,041	6,179,041	6,527,325	6,086,858	6,707,966	6,617,646	496	485	485	485	485
WE Energies	Presque Isle	9	solid		0.15	1.00		6,120,605	6,120,605	6,530,974	5,654,870	6,569,457	6,550,216	491	480	480	480	480

Source information								Annual Values					Calculations					
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (*if appropriate)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arithmetic average**	**2001 Heat Input**	**2002 Heat Input**	**2003 Heat Input**	**2004 Heat Input**	**2005 Heat Input**	**Highest 2 year average**	**Calc'd CAIR**	**Adjusted 2010 CAIR**	**Corrected (Rounding) 2009**	**Corrected (Rounding) 2010**	**Corrected (Rounding) 2011**
Wyandotte DMS	Wyandotte	5	gas		0.15	0.40		12,626	197,820	12,626	315,993	9,047	256,907	8	8	8	8	8
Wyandotte DMS	Wyandotte	7	solid		0.15	1.00		2,408,007	2,408,007	2,022,618	2,297,855	2,535,120	2,471,564	185	181	181	181	181
Wyandotte DMS	Wyandotte	8	solid		0.15	1.00		1,470,386	1,470,386	1,359,241	1,415,638	1,603,406	1,536,896	115	113	113	113	113
Corrections to the numbers include rounding up if greater than 0.5 to reach the target of 63,104														**64,608**	**63,104**	**63,104**	**63,104**	**63,104**

EGUs Ozone 2010_2011

	Source information		Operations Data						Ozone Season Values				Calculations				
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (*if appropriate)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arith. Ave.**	**2001 Heat Input**	**2002 Heat Input**	**2003 Heat Input**	**2004 Heat Input**	**2005 Heat Input**	**Highest 2 year average**	**Calculated CAIR**	**Adjusted CAIR**	**Corrected (Rounding) CAIR 2010**	**Corrected (Rounding) CAIR 2011**
CMS Gen/MI Pwr	Kalamazoo River	1	gas	**0.085**	0.15	0.40	**0.07**	15,852	9,065	23,332	57,415	164,297	110,856	4	4	5	5
CMS Gen/MI Pwr	Livingston Station	001	gas		0.15	0.40		36,182	10,364	21,187	17,436	97,869	67,026	2	2	3	3
CMS Gen/MI Pwr	Livingston Station	002	gas		0.15	0.40		34,315	11,323	22,562	16,274	91,409	62,862	2	2	3	3
CMS Gen/MI Pwr	Livingston Station	003	gas		0.15	0.40		33,365	14,142	21,436	7,605	112,306	72,836	2	2	3	3
CMS Gen/MI Pwr	Livingston Station	004	gas		0.15	0.40		34,952	8,070	21,498	16,378	91,463	63,208	2	2	3	3
CMS Generation	TES Filer City	B1	solid		0.15	1.00		1,336,192	1,106,298	1,156,981	1,372,265	1,170,467	1,354,229	102	101	101	101
CMS Generation	TES Filer City	B2	solid		0.15	1.00		1,336,192	1,106,298	1,156,981	1,372,265	1,170,467	1,354,229	102	101	95	95
Consumers Energy	Campbell	1	solid		0.15	1.00		5,825,632	9,656,016	9,264,652	9,129,636	8,818,480	9,460,334	710	708	708	708
Consumers Energy	Campbell	2	solid		0.15	1.00		9,766,936	10,786,454	9,478,872	8,587,537	10,363,935	10,575,195	793	792	792	792
Consumers Energy	Campbell	3	solid		0.15	1.00		27,634,659	25,298,815	26,346,455	21,541,780	24,446,249	26,990,557	2,024	2,020	2,020	2,020
Consumers Energy	Cobb	1	gas		0.15	0.40		238,349	176,489	47,190	295	241,779	240,064	7	7	8	8
Consumers Energy	Cobb	2	gas		0.15	0.40		219,116	164,021	47,935	227	231,899	225,508	7	7	8	8
Consumers Energy	Cobb	3	gas		0.15	0.40		269,215	179,793	7,820	133	209,770	239,493	7	7	8	8
Consumers Energy	Cobb	4	solid		0.15	1.00		5,067,731	4,901,417	5,014,409	5,168,580	4,737,228	5,118,156	384	383	383	383
Consumers Energy	Cobb	5	solid		0.15	1.00		5,133,332	5,748,538	5,462,145	5,388,203	5,645,708	5,697,123	427	426	426	426
Consumers Energy	Karn	1	solid		0.15	1.00		7,939,290	8,153,810	7,318,814	9,020,946	8,989,896	9,005,421	675	674	674	674
Consumers Energy	Karn	2	solid		0.15	1.00		8,784,336	8,192,913	8,530,178	8,706,408	8,155,171	8,745,372	656	655	655	655
Consumers Energy	Karn	3	gas		0.15	0.40		5,430,089	5,170,520	2,218,160	1,855,796	3,299,962	5,300,305	159	159	159	159
Consumers Energy	Karn	4	gas		0.15	0.40		4,881,440	2,936,278	1,434,765	925,404	3,052,820	3,967,130	119	119	119	119
Consumers Energy	Thetford CT	1	gas		0.15	0.40		16,419	8,057	5,286	5,097	67,514	41,967	1	1	2	2
Consumers Energy	Thetford CT	2	gas		0.15	0.40		13,187	7,135	5,138	9,061	76,392	44,790	1	1	2	2
Consumers Energy	Thetford CT	3	gas		0.15	0.40		11,900	8,192	3,289	5,884	81,010	46,455	1	1	2	2
Consumers Energy	Thetford CT	4	gas		0.15	0.40		5,791	7,160	3,384	5,317	85,354	46,257	1	1	2	2
Consumers Energy	Weadock	7	solid		0.15	1.00		4,348,739	5,018,497	5,452,648	2,116,734	4,908,424	5,235,573	393	392	392	392
Consumers Energy	Weadock	8	solid		0.15	1.00		6,069,066	5,199,624	5,008,404	4,898,152	4,604,032	5,634,345	423	422	422	422
Consumers Energy	Whiting	1	solid		0.15	1.00		3,599,715	3,822,763	3,869,579	3,325,270	3,687,577	3,846,171	288	288	288	288
Consumers Energy	Whiting	2	solid		0.15	1.00		3,813,878	3,541,774	3,159,438	3,340,048	3,822,454	3,818,166	286	286	286	286
Consumers Energy	Whiting	3	solid		0.15	1.00		3,546,075	4,574,997	4,238,361	4,422,438	3,421,846	4,498,718	337	337	337	337
Covert Generating LLC	Covert	1	gas		0.15	0.40		0	0	371,134	273,364	1,868,854	1,119,994	34	34	34	34
Covert Generating LLC	Covert	2	gas		0.15	0.40		0	0	1,005,724	326,686	2,113,179	1,559,452	47	47	47	47
Covert Generating LLC	Covert	3	gas		0.15	0.40		0	0	0	732,023	1,977,411	1,354,717	41	41	41	41
Dearborn Ind. Gen.	Dearborn Ind.	B1	gas	**0.1**	0.15	0.40	**0.08**	593,471	937,146	853,156	1,201,772	1,209,244	1,205,508	48	48	48	48
Dearborn Ind. Gen.	Dearborn Ind.	B2	gas	**0.1**	0.15	0.40	**0.08**	546,149	795,476	750,084	1,065,997	1,292,908	1,179,452	47	47	47	47
Dearborn Ind. Gen.	Dearborn Ind.	B3	gas	**0.1**	0.15	0.40	**0.08**	400,740	967,910	936,236	1,115,810	1,107,594	1,111,702	44	44	44	44
Dearborn Ind. Gen.	Dearborn Ind.	GTP1	gas	**0.033**	0.15	0.40	**0.05**	381,690	541,442	67,936	187,512	996,596	769,019	18	18	19	19
Detroit Edison	Belle River	1	solid		0.15	1.00		23,555,397	23,123,094	20,622,904	18,214,949	18,538,481	23,339,246	1,750	1,747	1,747	1,747
Detroit Edison	Belle River	2	solid		0.15	1.00		17,421,262	17,421,262	18,978,701	19,781,320	19,900,880	19,841,100	1,488	1,485	1,485	1,485
Detroit Edison	Belle River	CTG121	gas	**0.05**	0.15	0.40	**0.06**	468,999	468,999	172,368	78,801	431,154	468,999	13	13	14	14
Detroit Edison	Belle River	CTG122	gas	**0.05**	0.15	0.40	**0.06**	413,930	413,930	133,262	62,515	422,589	418,260	12	11	12	12
Detroit Edison	Belle River	CTG131	gas	**0.05**	0.15	0.40	**0.06**	233,265	233,265	149,076	97,269	430,834	332,050	9	9	10	10
Detroit Edison	Connors Creek	15	gas		0.15	0.40		264,579	173,189	102,378	146,271	371,019	317,799	10	10	11	11
Detroit Edison	Connors Creek	16	gas		0.15	0.40		275,811	154,809	74,398	104,645	317,497	296,654	9	9	10	10
Detroit Edison	Connors Creek	17	gas		0.15	0.40		236,329	155,381	99,776	142,950	277,818	257,074	8	8	9	9
Detroit Edison	Connors Creek	18	gas		0.15	0.40		265,137	130,002	83,168	131,750	319,128	292,133	9	9	10	10
Detroit Edison	Delray	CTG111	gas	**0.08**	0.15	0.40	**0.07**	147,660	285,148	101,493	81,174	175,399	230,274	8	8	9	9
Detroit Edison	Delray	CTG121	gas	**0.08**	0.15	0.40	**0.07**	143,075	270,644	84,738	100,543	269,442	270,043	9	9	10	10
Detroit Edison	East China	1	gas	**0.1**	0.15	0.40	**0.08**	0	45,663	90,022	0	265,055	177,539	7	7	8	8
Detroit Edison	East China	2	gas	**0.1**	0.15	0.40	**0.08**	0	45,653	93,865	0	271,955	182,910	7	7	8	8
Detroit Edison	East China	3	gas	**0.1**	0.15	0.40	**0.08**	0	45,266	91,329	0	271,716	181,523	7	7	8	8
Detroit Edison	East China	4	gas	**0.1**	0.15	0.40	**0.08**	0	42,601	92,771	0	247,276	170,024	7	7	8	8
Detroit Edison	Greenwood	1	gas/oil		0.15	0.40		3,590,124	5,891,836	2,941,199	2,850,058	5,502,957	5,697,397	171	171	171	171
Detroit Edison	Greenwood	CTG111	gas	**0.05**	0.15	0.40	**0.06**	247,294	303,922	102,717	17,393	458,781	381,352	10	10	11	11
Detroit Edison	Greenwood	CTG112	gas	**0.05**	0.15	0.40	**0.06**	229,789	340,063	72,515	17,865	458,719	399,391	11	11	12	12
Detroit Edison	Greenwood	CTG121	gas	**0.05**	0.15	0.40	**0.06**	207,889	307,479	82,515	15,640	175,347	257,684	7	7	8	8
Detroit Edison	Hancock	12-1 (5)	gas		0.15	0.40		36,296	11,731	13,584	6,585	19,770	28,033	1	1	2	2
Detroit Edison	Hancock	12-2 (6)	gas		0.15	0.40		32,774	14,880	13,984	6,108	6,185	23,827	1	1	2	2
Detroit Edison	Harbor Beach	1	solid		0.15	1.00		886,276	1,392,559	930,857	908,046	1,588,783	1,490,671	112	112	112	112
Detroit Edison	Marysville	9	solid		0.15	1.00		232,906	0	0	0	0	116,453	9	9	10	10
Detroit Edison	Marysville	10	solid		0.15	1.00		192,778	0	0	0	0	96,389	7	7	8	8
Detroit Edison	Marysville	11	solid		0.15	1.00		260,579	0	0	0	0	130,290	10	10	11	11
Detroit Edison	Marysville	12	solid		0.15	1.00		258,099	0	0	0	0	129,050	10	10	11	11
Detroit Edison	Monroe	1	solid		0.15	1.00		17,492,847	18,595,486	15,073,173	16,557,060	18,389,509	18,492,498	1,387	1,384	1,384	1,384
Detroit Edison	Monroe	2	solid		0.15	1.00		16,688,797	18,827,566	14,858,228	15,715,116	19,300,902	19,064,234	1,430	1,427	1,427	1,427
Detroit Edison	Monroe	3	solid		0.15	1.00		21,487,673	15,732,334	16,431,860	15,452,971	20,834,667	21,161,170	1,587	1,584	1,534	1,534
Detroit Edison	Monroe	4	solid		0.15	1.00		20,852,783	16,089,078	25,444,853	19,562,301	21,031,549	23,238,201	1,743	1,739	1,739	1,739
Detroit Edison	River Rouge	1	gas		0.15	0.40		734,688	549,025	252,639	18,092	56,942	641,857	19	19	20	20
Detroit Edison	River Rouge	2	solid		0.15	1.00		4,336,362	7,791,035	6,867,920	6,828,431	6,211,562	7,329,478	550	549	549	549
Detroit Edison	River Rouge	3	solid		0.15	1.00		7,851,513	7,204,611	5,297,685	6,940,095	5,617,053	7,528,062	565	563	564	564
Detroit Edison	St. Clair	1	solid		0.15	1.00		3,373,070	3,764,301	2,847,462	3,940,939	3,658,570	3,852,620	289	288	288	288
Detroit Edison	St. Clair	2	solid		0.15	1.00		4,281,616	2,923,803	2,274,845	4,163,962	3,477,329	4,222,789	317	316	316	316

	Source information		Operations Data							Ozone Season Values			Calculations				
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (*if appropriate)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arith. Ave.**	**2001 Heat Input**	**2002 Heat Input**	**2003 Heat Input**	**2004 Heat Input**	**2005 Heat Input**	**Highest 2 year average**	**Calculated CAIR**	**Adjusted CAIR**	**Corrected (Rounding) CAIR 2010**	**Corrected (Rounding) CAIR 2011**
Detroit Edison	St. Clair	3	solid		0.15	1.00		3,008,751	4,555,274	3,914,288	3,486,917	3,514,243	4,234,781	318	317	317	317
Detroit Edison	St. Clair	4	solid		0.15	1.00		3,772,142	4,013,842	3,640,161	3,524,985	3,832,336	3,923,089	294	294	294	294
Detroit Edison	St. Clair	6	solid		0.15	1.00		8,196,682	777,948	7,777,085	7,669,330	7,174,177	7,986,884	599	598	598	598
Detroit Edison	St. Clair	7	solid		0.15	1.00		7,368,393	11,242,257	10,049,199	11,355,886	9,087,177	11,299,072	847	846	846	846
Detroit Edison	Trenton Channel	16	solid		0.15	1.00		1,621,211	1,586,628	1,633,487	2,106,205	1,696,304	1,901,255	143	142	142	142
Detroit Edison	Trenton Channel	17	solid		0.15	1.00		1,812,575	1,616,692	1,724,275	1,962,086	1,634,174	1,887,331	142	141	142	142
Detroit Edison	Trenton Channel	18	solid		0.15	1.00		1,810,842	1,690,135	1,370,815	1,974,104	1,636,049	1,892,473	142	142	142	142
Detroit Edison	Trenton Channel	19	solid		0.15	1.00		1,991,096	1,681,485	1,565,822	1,871,634	1,642,588	1,931,365	145	145	145	145
Detroit Edison	Trenton Channel	9A	solid		0.15	1.00		11,358,761	12,973,117	12,551,959	11,544,193	12,221,984	12,762,538	957	955	955	955
Detroit PLD	Mistersky	5	liquid		0.15	0.60		184,502	362,352	360,899	1,597,254	256,808	979,803	44	44	44	44
Detroit PLD	Mistersky	6	liquid		0.15	0.60		620,703	0	0	0	763,150	691,926	31	31	31	31
Detroit PLD	Mistersky	7	liquid		0.15	0.60		1,441,155	822,539	831,229	811,781	502,259	1,136,192	51	51	51	51
Detroit PLD	Mistersky	GT-1	gas		0.15	0.40		98,774	267,668	102,141	10,522	3,263	184,905	6	6	7	7
Dynegy	Renaissance	CT1	gas	**0.06**	0.15	0.40	**0.06**	0	731,088	242,131	539,089	856,389	793,739	24	24	24	24
Dynegy	Renaissance	CT2	gas	**0.06**	0.15	0.40	**0.06**	0	630,495	248,336	60,351	637,469	633,982	19	19	20	20
Dynegy	Renaissance	CT3	gas	**0.06**	0.15	0.40	**0.06**	0	0	231,850	89,086	1,032,719	632,285	19	19	20	20
Dynegy	Renaissance	CT4	gas	**0.06**	0.15	0.40	**0.06**	0	589,650	200,585	90,757	1,098,002	843,826	25	25	25	25
FirstEnergy Genco	Sumpter	1	gas	**0.1**	0.15	0.40	**0.08**	0	406,060	150,452	38,906		278,256	11	11	12	12
FirstEnergy Genco	Sumpter	2	gas	**0.1**	0.15	0.40	**0.08**	0	347,284	161,778	42,030		254,531	10	10	11	11
FirstEnergy Genco	Sumpter	3	gas	**0.1**	0.15	0.40	**0.08**	0	353,473	155,869	38,631		254,671	10	10	11	11
FirstEnergy Genco	Sumpter	4	gas	**0.1**	0.15	0.40	**0.08**	0	392,267	119,315	48,182		255,791	10	10	11	11
Grand Haven BLP	Sims	3	solid		0.15	1.00		1,898,647	1,296,186	1,523,167	1,454,537	2,123,868	2,011,257	151	151	151	151
Holland BPW	48th Street	7	gas		0.15	0.40		124,516	235,579	41,111	72,527	21,126	180,048	5	5	6	6
Holland BPW	48th Street	8	gas		0.15	0.40		44,613	89,537	52,342	5,337	33,238	70,940	2	2	3	3
Holland BPW	48th Street	9	gas	**0.125**	0.15	0.40	**0.09**	358,387	591,954	199,981	122,340	80,517	475,171	22	22	22	22
Holland BPW	De Young	5	solid		0.15	1.00		948,165	803,750	938,115	792,041	854,060	943,140	71	71	71	71
Kinder Morgan	Jackson Power	7EA	gas	**0.1**	0.15	0.40	**0.08**	0	1,130,664	234,816	100,155	624,055	877,360	35	35	35	35
Kinder Morgan	Jackson Power	LM1	gas	**0.1**	0.15	0.40	**0.08**	0	501,392	94,952	47,822	165,200	333,296	13	13	13	13
Kinder Morgan	Jackson Power	LM2	gas	**0.1**	0.15	0.40	**0.08**	0	474,468	90,670	51,947	178,235	326,352	13	13	13	13
Kinder Morgan	Jackson Power	LM3	gas	**0.1**	0.15	0.40	**0.08**	0	481,788	89,975	31,916	239,319	360,554	14	14	14	14
Kinder Morgan	Jackson Power	LM4	gas	**0.1**	0.15	0.40	**0.08**	0	472,039	86,174	44,937	168,090	320,065	13	13	14	14
Kinder Morgan	Jackson Power	LM5	gas	**0.1**	0.15	0.40	**0.08**	0	476,010	91,338	37,494	241,330	358,670	14	14	15	15
Kinder Morgan	Jackson Power	LM6	gas	**0.1**	0.15	0.40	**0.08**	0	445,966	90,252	34,750	184,458	315,212	13	13	14	14
Lansing BWL	Eckert Station	1	solid		0.15	1.00		1,143,329	1,026,237	1,102,483	821,432	1,074,937	1,122,906	84	84	84	84
Lansing BWL	Eckert Station	2	solid		0.15	1.00		1,186,242	1,074,194	846,646	1,111,662	1,076,943	1,148,952	86	86	86	86
Lansing BWL	Eckert Station	3	solid		0.15	1.00		964,397	1,287,915	993,046	1,279,568	1,157,984	1,283,741	96	96	96	96
Lansing BWL	Eckert Station	4	solid		0.15	1.00		2,367,356	2,385,076	2,203,249	2,077,336	1,662,640	2,376,216	178	178	178	178
Lansing BWL	Eckert Station	5	solid		0.15	1.00		2,165,973	1,849,618	2,013,728	1,831,202	1,940,194	2,089,851	157	156	156	156
Lansing BWL	Eckert Station	6	solid		0.15	1.00		2,032,491	2,069,183	2,337,225	2,054,908	2,170,881	2,254,053	169	169	169	169
Lansing BWL	Erickson	1	solid		0.15	1.00		3,693,555	4,517,260	4,400,621	5,261,478	4,631,599	4,946,539	371	370	370	370
Marquette. City of	Shiras	3	solid		0.15	1.00		0	0	1,483,274	1,426,510	1,541,974	1,512,624	113	113	113	113
Michigan Power LP	MI Power LP	G101	gas		0.15	0.40		3,233,935	3,955,825	4,185,936	4,239,769		4,212,853	126	126	126	126
Michigan Public Pwr	Kalkaska CT #1	1A	gas		0.15	0.40		0	0	35,572	28,652	18,319	32,112	1	1	2	2
Michigan Public Pwr	Kalkaska CT #1	1B	gas		0.15	0.40		0	0	42,094	18,672	25,901	33,998	1	1	2	2
Midland Cogen V.	Midland Cogen V.	GT10	gas		0.15	0.40		2,835,697	2,942,063	1,846,750	3,316,802	**1,129,042**	3,129,433	94	94	94	94
Midland Cogen V.	Midland Cogen V.	GT11	gas		0.15	0.40		2,946,020	2,780,781	2,357,289	3,469,206	**1,023,090**	3,207,613	96	96	96	96
Midland Cogen V.	Midland Cogen V.	GT12	gas	**0.14**	0.15	0.40	**0.10**	2,967,937	2,590,448	2,208,822	2,873,083	**837,169**	2,920,510	146	146	146	146
Midland Cogen V.	Midland Cogen V.	GT13	gas		0.15	0.40		3,429,136	2,602,609	2,402,117	3,449,706	**1,992,625**	3,439,421	103	103	103	103
Midland Cogen V.	Midland Cogen V.	GT14	gas		0.15	0.40		2,785,723	2,769,489	2,051,357	3,430,408	**2,934,541**	3,182,475	95	95	95	95
Midland Cogen V.	Midland Cogen V.	GT3	gas		0.15	0.40		2,846,179	2,796,031	2,452,391	3,450,372	**3,132,745**	3,291,558	99	99	99	99
Midland Cogen V.	Midland Cogen V.	GT4	gas		0.15	0.40		2,844,802	2,617,087	2,005,540	3,076,639	**2,869,075**	2,972,857	89	89	89	89
Midland Cogen V.	Midland Cogen V.	GT5	gas		0.15	0.40		3,123,470	2,428,780	2,238,597	3,468,621	**3,205,444**	3,337,032	100	100	100	100
Midland Cogen V.	Midland Cogen V.	GT6	gas		0.15	0.40		2,662,165	2,817,748	2,302,016	2,802,131	**3,273,214**	3,045,481	91	91	91	91
Midland Cogen V.	Midland Cogen V.	GT7	gas		0.15	0.40		2,702,821	2,522,885	2,085,773	3,343,686	**1,195,739**	3,023,253	91	91	91	91
Midland Cogen V.	Midland Cogen V.	GT8	gas		0.15	0.40		3,415,266	2,714,763	1,907,861	3,386,643	**1,236,445**	3,400,955	102	102	102	102
Midland Cogen V.	Midland Cogen V.	GT9	gas		0.15	0.40		2,914,151	2,734,935	2,402,623	3,326,102	**1,091,026**	3,120,127	94	93	93	93
Mirant Zeeland	Zeeland Power	1	gas	**0.04**	0.15	0.40	**0.05**	0	405,761	87,396	0	267,884	336,823	8	8	9	9
Mirant Zeeland	Zeeland Power	2	gas	**0.04**	0.15	0.40	**0.05**	0	441,527	107,710	32,773	141,086	291,307	7	7	8	8
Mirant Zeeland	Zeeland Power	3	gas	**0.13**	0.15	0.40	**0.10**	0	392,355	632,162	436,904	1,482,883	1,057,523	50	50	50	50
Mirant Zeeland	Zeeland Power	4	gas	**0.13**	0.15	0.40	**0.10**	0	488,899	567,687	454,020	1,624,690	1,096,189	52	52	52	52
MSCPA	Enidcott Gen St	1	solid		0.15	1.00		2,138,460	2,370,990	2,434,400	2,393,181	2,936,538	2,685,469	201	201	201	201
WE Energies	Presque Isle	2	solid		0.15	1.00		190,366	38,284	23,128	247,721	364,690	306,206	23	23	23	23
WE Energies	Presque Isle	3	solid		0.15	1.00		1,269,787	1,618,431	872,543	1,442,607	1,956,512	1,787,471	134	134	134	134
WE Energies	Presque Isle	4	solid		0.15	1.00		1,552,312	992,844	1,462,748	1,449,428	1,603,343	1,577,828	118	118	118	118
WE Energies	Presque Isle	5	solid		0.15	1.00		2,603,708	2,697,695	2,061,455	2,230,869	2,442,717	2,650,702	199	198	198	198
WE Energies	Presque Isle	6	solid		0.15	1.00		2,400,204	1,883,125	1,747,689	2,422,968	2,303,735	2,411,586	181	181	181	181
WE Energies	Presque Isle	7	solid		0.15	1.00		2,793,954	3,041,844	2,304,342	2,933,879	3,203,683	3,122,764	234	234	234	234
WE Energies	Presque Isle	8	solid		0.15	1.00		2,887,178	2,849,342	2,735,688	3,033,454	2,706,456	2,960,316	222	222	222	222
WE Energies	Presque Isle	9	solid		0.15	1.00		2,785,069	2,868,513	2,270,262	2,721,706	2,798,186	2,833,349	213	212	212	212

	Source information		Operations Data					Ozone Season Values					Calculations				
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (*if appropriate)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arith. Ave.**	**2001 Heat Input**	**2002 Heat Input**	**2003 Heat Input**	**2004 Heat Input**	**2005 Heat Input**	**Highest 2 year average**	**Calculated CAIR**	**Adjusted CAIR**	**Corrected (Rounding) CAIR 2010**	**Corrected (Rounding) CAIR 2011**
Wyandotte DMS	Wyandotte	5	gas		0.150	0.40		8,206	132,210	0	0	0	70,208	2	2	3	3
Wyandotte DMS	Wyandotte	7	solid		0.15	1.00		1,171,110	872,353	1,046,510	1,053,652	1,231,693	1,201,401	90	90	90	90
Wyandotte DMS	Wyandotte	8	solid		0.150	1.00		759,889	593,742	547,727	758,940	899,589	829,739	62	62	62	62
Corrections to the numbers include rounding up if greater than 0.5 and adding 1 allowance to each value that was a less than 13 to reach the target of 28,321														**28,378**	**28,321**	**28,321**	**28,321**

AMENDED SPREADSHEETS

AVAILABLE AT THE

APRIL 2, 2007

PUBLIC HEARING

STAFF STATEMENT

AIR QUALITY DIVISION
DEPARTMENT OF ENVIRONMENTAL QUALITY

By: Teresa Walker, Strategy Development Unit

April 2, 2007

SUBJECT: Proposed administrative rules R 336.1802a, R 336.1803, R 336.1821 to R 336.1826, and R 336.1830 to R 336.1834.

PRINCIPAL REASONS FOR THE PROPOSED RULES

These rules are being developed to meet requirements of the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR) to reduce transported emissions of oxides of nitrogen (NOx) from electric generating units (EGUs) and large non-electric generating units. The rules will be submitted to the EPA as part of the Michigan State Implementation Plan (SIP) upon final promulgation.

The federal CAIR program requires the state to develop the regulations to reduce NOx emissions. The proposed rules will result in reduced NOx emissions from EGUs and large non-EGUs, which will help reduce the formation of particulate matter less than 2.5 microns in diameter and ground-level ozone in Michigan and downwind areas. The Department of Environmental Quality (DEQ) worked with a number of stakeholders to develop and adopt these rules. The workgroup included representatives from various industrial, commercial, small business, consumer and environmental groups, and associations. The workgroup met several times during 2005 and 2006.

SUMMARY OF THE CONTENTS OF THE PROPOSED RULES

Rules 802a, 803, 821 through 826, and 830 through 834 are based on the EPA CAIR rules, a NOx emissions cap and trade system to be administered by the EPA.

- Rule 802a contains language adopting specific provisions of 40 CFR Parts 72, 75 and 97 by reference, pursuant to the federal CAIR program requirements.
- Revisions to Rule 803 modify the existing definitions to address the CAIR requirements.
- Rule 821 contains applicability criteria.
- Rule 822 establishes the NOx budgets for the ozone season control period and establishes the allocation methodology procedures for the ozone season. See the attached spreadsheets for the allocation tables for each group.
- Rule 823 establishes the provisions for a new source set-aside ozone season control period allocation pool for new EGUs, new non-EGUS, and newly affected EGUS (which were not included in the original NOx program due to geographic location).

- Rule 824 establishes the provisions for a hardship set-aside ozone season control period allocation pool to address issues for small businesses that are impacted by the rules.
- Rule 825 establishes the provisions for a renewable set-aside ozone season control period allocation pool to encourage the use of renewable energy in the production of electricity in the state.
- Rule 826 adopts by reference the ozone season control period opt-in provisions under the federal CAIR rules.
- Rule 830 establishes the NOx budgets for the annual control period and establishes the allocation methodology procedures for the annual control period. See the attached spreadsheets for the allocation tables for each group.
- Rule 831 establishes the provisions for a new source set-aside annual control period allocation pool for new EGUs.
- Rule 832 establishes the provisions for a hardship set-aside annual control period allocation pool to address issues for small businesses that are impacted by the rules.
- Rule 833 establishes the provisions for an annual control period compliance supplement pool with early reduction credit generation and hardship provisions for the newly affected EGUs that were not in the original NOx Budget Program and are adversely impacted by this new program for 2009.
- Rule 834 adopts by reference the opt-in provisions for the annual control period under the federal CAIR rules.

Allocation spreadsheets are also being made part of this public hearing and will become part of the SIP Submittal. Due to comments from the affected facilities, the allocation spreadsheets have been modified from the originals sent out. These updates include corrections to heat input values and fuel type factors. The corrected sheets were made available to the members of the workgroup on Friday March 30, 2007, and copies are available here.

That concludes my statements on the proposed rule revisions.

	Source information											Annual Values			
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arith. average**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**
Cadillac RE	Cadillac Renew	GEN1	solid		0.15	1.00			3,739,212			3,401,849			3,298,996
CMS Gen/MI Pwr	Kalamazoo River	1	gas	**0.085**	0.15	0.40	**0.07**		16,152			11,849			24,040
CMS Gen/MI Pwr	Livingston Station	001	gas		0.15	0.40			36,696			11,165			24,444
CMS Gen/MI Pwr	Livingston Station	002	gas		0.15	0.40			34,566			11,963			25,673
CMS Gen/MI Pwr	Livingston Station	003	gas		0.15	0.40			34,042			14,776			21,765
CMS Gen/MI Pwr	Livingston Station	004	gas		0.15	0.40			35,690			9,248			21,530
CMS Generation	Genesee Power	GEN1	solid		0.15	1.00			3,119,509			2,989,823			3,262,440
CMS Generation	Grayling Station	GEN1	solid		0.15	1.00			3,393,669			2,893,805			3,301,806
CMS Generation	TES Filer City	B1	solid		0.15	1.00			2,731,978			2,695,191			2,782,690
CMS Generation	TES Filer City	B2	solid		0.15	1.00			2,731,978			2,695,191			2,782,690
Consumers Energy	Campbell	1	solid		0.15	1.00			13,155,517			21,798,697			21,367,302
Consumers Energy	Campbell	2	solid		0.15	1.00			24,125,827			24,312,028			22,594,539
Consumers Energy	Campbell	3	solid		0.15	1.00			62,570,086			53,055,997			67,055,963
Consumers Energy	Cobb	1	gas		0.15	0.40			278,874			185,467			47,190
Consumers Energy	Cobb	2	gas		0.15	0.40			255,344			169,559			47,935
Consumers Energy	Cobb	3	gas		0.15	0.40			306,620			190,193			7,820
Consumers Energy	Cobb	4	solid		0.15	1.00			12,357,348			11,352,929			11,950,163
Consumers Energy	Cobb	5	solid		0.15	1.00			10,219,548			12,591,560			11,499,723
Consumers Energy	Karn	1	solid		0.15	1.00			17,877,384			18,511,275			19,068,898
Consumers Energy	Karn	2	solid		0.15	1.00			20,219,624			20,039,578			16,067,341
Consumers Energy	Karn	3	dual		0.15	0.40		0.48	7,771,450	3,721,584	0.50	6,915,250	3,440,141	0.55	3,361,613
Consumers Energy	Karn	4	dual		0.15	0.40		**0.46**	6,763,915	3,130,677	0.50	4,786,746	2,372,763	0.54	2,576,621
Consumers Energy	Thetford CT	1	gas		0.15	0.40			23,875			20,227			22,049
Consumers Energy	Thetford CT	2	gas		0.15	0.40			18,250			20,168			17,014
Consumers Energy	Thetford CT	3	gas		0.15	0.40			13,958			19,054			19,197
Consumers Energy	Thetford CT	4	gas		0.15	0.40			7,208			12,970			17,918
Consumers Energy	Weadock	7	solid		0.15	1.00			10,420,490			12,239,672			12,822,427
Consumers Energy	Weadock	8	solid		0.15	1.00			14,062,399			11,622,625			12,692,967
Consumers Energy	Whiting	1	solid		0.15	1.00			7,539,106			8,907,503			8,924,762
Consumers Energy	Whiting	2	solid		0.15	1.00			8,759,753			7,879,230			8,503,714
Consumers Energy	Whiting	3	solid		0.15	1.00			9,101,039			10,278,867			9,926,144
Covert Generating LLC	Covert	1	gas	**0.009**	0.15	0.40	**0.03**		0			0			1,872,810
Covert Generating LLC	Covert	2	gas	**0.009**	0.15	0.40	**0.03**		0			0			5,295,970
Covert Generating LLC	Covert	3	gas	**0.009**	0.15	0.40	**0.03**		0			0			1,718,682
Dearborn Ind. Gen.	Dearborn Ind.	B1	gas	**0.1**	0.15	0.40	**0.08**		806,355			2,437,348			2,504,066
Dearborn Ind. Gen.	Dearborn Ind.	B2	gas	**0.1**	0.15	0.40	**0.08**		697,601			2,142,750			2,785,766
Dearborn Ind. Gen.	Dearborn Ind.	B3	gas	**0.1**	0.15	0.40	**0.08**		628,487			2,654,975			2,510,858
Dearborn Ind. Gen.	Dearborn Ind.	GTP1	gas	**0.033**	0.15	0.40	**0.05**		450,275			595,935			67,937
Detroit Edison	Belle River	1	solid		0.15	1.00			52,284,748			55,238,546			39,503,328
Detroit Edison	Belle River	2	solid		0.15	1.00			50,693,844			32,606,529			48,243,589
Detroit Edison	Belle River	CTG121	gas	**0.033**	0.15	0.40	**0.05**		562,427			858,536			401,816
Detroit Edison	Belle River	CTG122	gas	**0.033**	0.15	0.40	**0.05**		401,119			661,034			286,576
Detroit Edison	Belle River	CTG131	gas	**0.033**	0.15	0.40	**0.05**		403,326			580,541			302,417
Detroit Edison	Connors Creek	15	gas		0.15	0.40			264,972			260,081			102,378
Detroit Edison	Connors Creek	16	gas		0.15	0.40			276,197			220,549			74,398
Detroit Edison	Connors Creek	17	gas		0.15	0.40			236,651			146,908			99,776
Detroit Edison	Connors Creek	18	gas		0.15	0.40			265,491			203,715			83,168
Detroit Edison	Delray	CTG111	gas	**0.055**	0.15	0.40	**0.06**		206,339			397,717			233,605
Detroit Edison	Delray	CTG121	gas	**0.055**	0.15	0.40	**0.06**		182,261			383,730			207,170
Detroit Edison	East China	1	gas	**0.036**	0.15	0.40	**0.05**		0			66,874			112,328
Detroit Edison	East China	2	gas	**0.036**	0.15	0.40	**0.05**		0			67,436			93,866
Detroit Edison	East China	3	gas	**0.036**	0.15	0.40	**0.05**		0			85,737			91,329
Detroit Edison	East China	4	gas	**0.036**	0.15	0.40	**0.05**		0			62,264			105,886
Detroit Edison	Greenwood	1	dual		0.15	0.40		0.45	9,673,911	4,362,635	0.48	11,701,703	5,621,270	0.50	6,969,328
Detroit Edison	Greenwood	CTG111	gas	**0.033**	0.15	0.40	**0.05**		438,076			606,876			203,477
Detroit Edison	Greenwood	CTG112	gas	**0.033**	0.15	0.40	**0.05**		320,807			544,587			121,400
Detroit Edison	Greenwood	CTG121	gas	**0.033**	0.15	0.40	**0.05**		342,731			500,185			124,811
Detroit Edison	Hancock	12-1 (5)	gas		0.15	0.40			58,068			27,962			51,901
Detroit Edison	Hancock	12-2 (6)	gas		0.15	0.40			47,967			29,623			51,516
Detroit Edison	Harbor Beach	1	solid		0.15	1.00			2,283,416			2,737,110			2,291,301

	Source information											Annual Values			
Company Name	Plant Name	Unit ID	Fuel Type	Permit Limit (if applicable)	Emission Factor 2010-2014	Fuel Adj Factor	Arith. average	2001 Fuel Ratio	2001 Heat Input	2001 Adjusted Heat Input	2002 Fuel Ratio	2002 Heat Input	2002 Adjusted Heat Input	2003 Fuel Ratio	2003 Heat Input
Detroit Edison	Marysville	9	solid		0.15	1.00			508,369			0			0
Detroit Edison	Marysville	10	solid		0.15	1.00			406,858			0			0
Detroit Edison	Marysville	11	solid		0.15	1.00			431,617			0			0
Detroit Edison	Marysville	12	solid		0.15	1.00			517,072			0			0
Detroit Edison	Monroe	1	solid		0.15	1.00			31,787,539			37,900,714			36,375,042
Detroit Edison	Monroe	2	solid		0.15	1.00			40,137,687			44,583,407			34,080,756
Detroit Edison	Monroe	3	solid		0.15	1.00			48,668,709			43,377,986			43,799,956
Detroit Edison	Monroe	4	solid		0.15	1.00			50,570,249			32,484,566			54,468,859
Detroit Edison	River Rouge	1	gas		0.15	0.40			736,582			551,706			253,473
Detroit Edison	River Rouge	2	solid		0.15	1.00			9,345,293			18,528,487			15,109,968
Detroit Edison	River Rouge	3	solid		0.15	1.00			15,960,363			15,942,526			13,589,912
Detroit Edison	St. Clair	1	solid		0.15	1.00			8,487,866			9,079,111			7,546,332
Detroit Edison	St. Clair	2	solid		0.15	1.00			9,993,401			5,359,011			4,186,272
Detroit Edison	St. Clair	3	solid		0.15	1.00			7,933,356			9,311,954			8,893,199
Detroit Edison	St. Clair	4	solid		0.15	1.00			8,484,952			9,604,699			8,873,193
Detroit Edison	St. Clair	6	solid		0.15	1.00			17,597,973			17,415,112			14,354,894
Detroit Edison	St. Clair	7	solid		0.15	1.00			8,608,084			22,691,354			26,088,697
Detroit Edison	Trenton Channel	16	solid		0.15	1.00			4,370,089			4,332,832			4,129,570
Detroit Edison	Trenton Channel	17	solid		0.15	1.00			4,106,432			4,346,912			4,317,456
Detroit Edison	Trenton Channel	18	solid		0.15	1.00			4,331,407			4,081,311			3,731,234
Detroit Edison	Trenton Channel	19	solid		0.15	1.00			4,408,814			3,688,673			4,162,144
Detroit Edison	Trenton Channel	9A	solid		0.15	1.00			28,407,802			29,653,709			24,008,693
Detroit PLD	Mistersky	5	gas		0.15	0.40			2,070,750			3,191,905			3,460,811
Detroit PLD	Mistersky	6	gas		0.15	0.40			3,140,297			0			0
Detroit PLD	Mistersky	7	gas		0.15	0.40			5,097,835			2,806,482			2,980,302
Detroit PLD	Mistersky	GT-1	liquid		0.15	0.60			0			0			181,548
Dynegy	Renaissance	CT1	gas	**0.055**	0.15	0.40	**0.06**		0			841,395			273,356
Dynegy	Renaissance	CT2	gas	**0.055**	0.15	0.40	**0.06**		0			715,802			301,577
Dynegy	Renaissance	CT3	gas	**0.055**	0.15	0.40	**0.06**		0			0			232,760
Dynegy	Renaissance	CT4	gas	**0.055**	0.15	0.40	**0.06**		0			670,238			263,805
FirstEnergy Genco	Sumpter	1	gas	**0.1**	0.15	0.40	**0.08**		0			452,170			166,862
FirstEnergy Genco	Sumpter	2	gas	**0.1**	0.15	0.40	**0.08**		0			392,970			166,065
FirstEnergy Genco	Sumpter	3	gas	**0.1**	0.15	0.40	**0.08**		0			399,361			171,321
FirstEnergy Genco	Sumpter	4	gas	**0.1**	0.15	0.40	**0.08**		0			438,019			128,865
Grand Haven BLP	Sims	3	solid		0.15	1.00			4,365,200			2,926,603			3,964,594
Holland BPW	48th Street	7	gas		0.15	0.40			151,225			310,743			72,621
Holland BPW	48th Street	8	gas		0.15	0.40			47,964			97,091			57,104
Holland BPW	48th Street	9	gas	**0.081**	0.15	0.40	**0.07**		392,477			719,906			330,582
Holland BPW	De Young	5	solid		0.15	1.00			2,287,121			1,905,187			2,327,238
Kinder Morgan	Jackson Power	7EA	gas	**0.033**	0.15	0.40	**0.05**		0			963,486			227,749
Kinder Morgan	Jackson Power	LM1	gas	**0.081**	0.15	0.40	**0.07**		0			419,567			98,610
Kinder Morgan	Jackson Power	LM2	gas	**0.081**	0.15	0.40	**0.07**		0			407,496			91,865
Kinder Morgan	Jackson Power	LM3	gas	**0.081**	0.15	0.40	**0.07**		0			263,485			89,200
Kinder Morgan	Jackson Power	LM4	gas	**0.081**	0.15	0.40	**0.07**		0			398,951			85,436
Kinder Morgan	Jackson Power	LM5	gas	**0.081**	0.15	0.40	**0.07**		0			409,984			89,013
Kinder Morgan	Jackson Power	LM6	gas	**0.081**	0.15	0.40	**0.07**		0			385,428			85,759
Lansing BWL	Eckert Station	1	solid		0.15	1.00			2,193,141			2,390,490			2,735,145
Lansing BWL	Eckert Station	2	solid		0.15	1.00			2,250,051			2,200,642			1,516,592
Lansing BWL	Eckert Station	3	solid		0.15	1.00			1,794,677			3,015,535			2,491,150
Lansing BWL	Eckert Station	4	solid		0.15	1.00			5,135,689			5,455,215			5,541,731
Lansing BWL	Eckert Station	5	solid		0.15	1.00			5,210,424			4,409,146			4,689,097
Lansing BWL	Eckert Station	6	solid		0.15	1.00			4,270,493			4,498,764			5,018,062
Lansing BWL	Erickson	1	solid		0.15	1.00			7,364,811			8,726,322			9,905,662
Marquette. City of	Shiras	3	solid		0.15	1.00			3,897,490			3,551,115			3,793,130
Michigan Power LP	MI Power LP	G101	gas	**0.05**	0.15	0.40	**0.06**		8,158,601			9,614,040			10,029,672
Michigan Public Pwr	Kalkaska CT #1	1A	gas	**0.092**	0.15	0.40	**0.08**		0			0			46,508
Michigan Public Pwr	Kalkaska CT #1	1B	gas	**0.092**	0.15	0.40	**0.08**		0			0			55,074
Midland Cogen V.	Midland Cogen V.	GT10	gas		0.15	0.40			6,248,493			5,591,400			5,019,880
Midland Cogen V.	Midland Cogen V.	GT11	gas		0.15	0.40			6,871,055			5,670,918			5,174,188
Midland Cogen V.	Midland Cogen V.	GT12	gas	**0.14**	0.15	0.40	**0.10**		6,373,823			5,027,637			4,577,762

	Source information											Annual Values			
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arith. average**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**
Midland Cogen V.	Midland Cogen V.	GT13	gas		0.15	0.40			7,278,544			6,070,442			5,595,108
Midland Cogen V.	Midland Cogen V.	GT14	gas		0.15	0.40			6,244,846			6,440,071			5,842,690
Midland Cogen V.	Midland Cogen V.	GT3	gas		0.15	0.40			6,265,292			7,626,419			6,212,930
Midland Cogen V.	Midland Cogen V.	GT4	gas		0.15	0.40			7,326,288			6,473,233			5,867,439
Midland Cogen V.	Midland Cogen V.	GT5	gas		0.15	0.40			5,643,725			6,229,356			5,658,507
Midland Cogen V.	Midland Cogen V.	GT6	gas		0.15	0.40			5,759,330			6,916,087			6,245,468
Midland Cogen V.	Midland Cogen V.	GT7	gas		0.15	0.40			6,640,841			5,807,441			5,366,555
Midland Cogen V.	Midland Cogen V.	GT8	gas		0.15	0.40			7,667,023			6,480,616			5,815,477
Midland Cogen V.	Midland Cogen V.	GT9	gas		0.15	0.40			6,670,350			5,982,573			5,108,127
Mirant Zeeland	Zeeland Power	1	gas	**0.04**	0.15	0.40	**0.05**		715,823			512,684			116,802
Mirant Zeeland	Zeeland Power	2	gas	**0.04**	0.15	0.40	**0.05**		612,469			544,687			120,034
Mirant Zeeland	Zeeland Power	3	gas	**0.013**	0.15	0.40	**0.04**		0			1,318,948			1,282,492
Mirant Zeeland	Zeeland Power	4	gas	**0.013**	0.15	0.40	**0.04**		0			1,131,993			1,170,521
MSCPA	Enidcott Gen St	1	solid		0.15	1.00			4,552,863			4,907,732			5,416,634
WE Energies	Presque Isle	2	solid		0.15	1.00			878,397			56,936			472,939
WE Energies	Presque Isle	3	solid		0.15	1.00			3,307,534			3,576,072			3,272,809
WE Energies	Presque Isle	4	solid		0.15	1.00			4,170,172			2,869,877			3,904,275
WE Energies	Presque Isle	5	solid		0.15	1.00			5,506,259			6,084,423			4,214,515
WE Energies	Presque Isle	6	solid		0.15	1.00			6,479,197			5,194,678			5,527,597
WE Energies	Presque Isle	7	solid		0.15	1.00			6,275,974			6,288,693			6,381,585
WE Energies	Presque Isle	8	solid		0.15	1.00			6,179,041			6,527,325			6,086,858
WE Energies	Presque Isle	9	solid		0.15	1.00			6,120,605			6,530,974			5,654,869
Wyandotte DMS	Wyandotte	5	gas		0.15	0.40			12,627			315,993			9,047
Wyandotte DMS	Wyandotte	7	solid		0.15	1.00			2,408,007			2,022,617			2,297,856
Wyandotte DMS	Wyandotte	8	solid		0.15	1.00			1,470,385			1,359,241			1,415,637

Corrections to the numbers include rounding up if greater than 0.5 to reach the target of 63,104

	Source information									Calculations				
Company Name	**Plant Name**	**Unit ID**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**	**2004 Adjusted Heat Input**	**2005 Fuel Ratio**	**2005 Heat Input**	**2005 Adjusted Heat Input**	**Highest 2 year average**	**Calc'd CAIR**	**Adjusted 2010 CAIR**	**Corrected (Rounding) 2009**	**Corrected (Rounding) 2010**
Cadillac RE	Cadillac Renew	GEN1			3,409,205			3,382,278		3,574,209	268	259	259	259
CMS Gen/MI Pwr	Kalamazoo River	1			68,053			164,296		116,175	4	4	4	4
CMS Gen/MI Pwr	Livingston Station	001			17,606			97,869		67,283	2	2	2	2
CMS Gen/MI Pwr	Livingston Station	002			16,443			91,409		62,988	2	2	2	2
CMS Gen/MI Pwr	Livingston Station	003			7,904			112,305		73,174	2	2	2	2
CMS Gen/MI Pwr	Livingston Station	004			16,698			91,463		63,577	2	2	2	2
CMS Generation	Genesee Power	GEN1			3,756,273			3,773,719		3,764,996	282	273	273	273
CMS Generation	Grayling Station	GEN1			3,924,770			3,597,115		3,760,943	282	273	273	273
CMS Generation	TES Filer City	B1			3,151,616			2,879,646		3,015,631	226	219	219	219
CMS Generation	TES Filer City	B2			3,151,616			2,879,646		3,015,631	226	219	219	219
Consumers Energy	Campbell	1			19,732,030			21,297,843		21,583,000	1,619	1,566	1,566	1,566
Consumers Energy	Campbell	2			21,102,965			21,630,551		24,218,928	1,816	1,758	1,758	1,758
Consumers Energy	Campbell	3			55,140,163			58,757,120		64,813,025	4,861	4,704	4,703	4,703
Consumers Energy	Cobb	1			295			241,779		260,327	8	8	8	8
Consumers Energy	Cobb	2			227			231,899		243,622	7	7	7	7
Consumers Energy	Cobb	3			133			209,770		258,195	8	7	7	7
Consumers Energy	Cobb	4			11,677,146			9,111,205		12,153,756	912	882	882	882
Consumers Energy	Cobb	5			11,527,460			13,644,417		13,117,989	984	952	952	952
Consumers Energy	Karn	1			15,836,937			20,199,031		19,633,965	1,473	1,425	1,425	1,425
Consumers Energy	Karn	2			20,141,106			19,801,360		20,180,365	1,514	1,465	1,465	1,465
Consumers Energy	Karn	3	1,832,201	0.57	2,984,763	1,698,688	0.50	4,655,426	2,315,545	3,580,863	269	260	260	260
Consumers Energy	Karn	4	1,395,176	0.58	1,124,380	646,563	0.48	3,554,310	1,711,656	2,751,720	206	200	200	200
Consumers Energy	Thetford CT	1			4,749			106,749		65,312	2	2	2	2
Consumers Energy	Thetford CT	2			10,671			114,759		67,464	2	2	2	2
Consumers Energy	Thetford CT	3			6,575			110,754		64,976	2	2	2	2
Consumers Energy	Thetford CT	4			6,191			122,786		70,352	2	2	2	2
Consumers Energy	Weadock	7			9,132,977			10,539,997		12,531,050	940	909	909	909
Consumers Energy	Weadock	8			12,303,429			12,225,783		13,377,683	1,003	971	971	971
Consumers Energy	Whiting	1			8,555,544			8,904,390		8,916,133	669	647	647	647
Consumers Energy	Whiting	2			8,571,610			9,265,577		9,012,665	676	654	654	654
Consumers Energy	Whiting	3			10,715,793			9,220,343		10,497,330	787	762	762	762
Covert Generating LLC	Covert	1			632,297			1,934,155		1,903,483	33	32	32	32
Covert Generating LLC	Covert	2			747,296			2,114,060		3,705,015	64	62	62	62
Covert Generating LLC	Covert	3			1,854,637			2,583,525		2,219,081	38	37	37	37
Dearborn Ind. Gen.	Dearborn Ind.	B1			2,890,126			3,644,590		3,267,358	131	126	126	126
Dearborn Ind. Gen.	Dearborn Ind.	B2			2,398,019			3,451,792		3,118,779	125	121	121	121
Dearborn Ind. Gen.	Dearborn Ind.	B3			2,895,188			3,682,266		3,288,727	132	127	127	127
Dearborn Ind. Gen.	Dearborn Ind.	GTP1			292,107			2,048,956		1,322,446	31	30	30	30
Detroit Edison	Belle River	1			47,984,884			43,592,569		53,761,647	4,032	3,902	3,902	3,902
Detroit Edison	Belle River	2			48,332,026			40,500,914		49,512,935	3,713	3,593	3,593	3,593
Detroit Edison	Belle River	CTG121			197,046			617,886		738,211	17	17	17	17
Detroit Edison	Belle River	CTG122			137,252			608,169		634,602	15	14	14	14
Detroit Edison	Belle River	CTG131			120,636			605,990		593,266	14	13	13	13
Detroit Edison	Connors Creek	15			146,630			389,921		327,447	10	10	10	10
Detroit Edison	Connors Creek	16			105,008			317,876		297,037	9	9	9	9
Detroit Edison	Connors Creek	17			143,831			282,956		259,804	8	8	8	8
Detroit Edison	Connors Creek	18			131,985			326,422		295,957	9	9	9	9
Detroit Edison	Delray	CTG111			152,365			344,895		371,306	11	10	10	10
Detroit Edison	Delray	CTG121			183,282			414,814		399,272	11	11	11	11
Detroit Edison	East China	1			0			265,296		188,812	5	4	4	4
Detroit Edison	East China	2			0			272,178		183,022	4	4	4	4
Detroit Edison	East China	3			0			293,095		192,212	5	4	4	4
Detroit Edison	East China	4			0			267,345		186,616	4	4	4	4
Detroit Edison	Greenwood	1	3,479,269	0.54	5,501,890	2,974,885	0.49	7,927,441	3,874,973	4,991,953	150	145	145	145
Detroit Edison	Greenwood	CTG111			24,408			542,453		574,665	13	13	13	13
Detroit Edison	Greenwood	CTG112			25,263			546,583		545,585	13	12	12	12
Detroit Edison	Greenwood	CTG121			23,250			180,528		421,458	10	9	9	9
Detroit Edison	Hancock	12-1 (5)			6,585			19,770		54,985	2	2	2	2
Detroit Edison	Hancock	12-2 (6)			6,108			6,185		49,742	1	1	1	1
Detroit Edison	Harbor Beach	1			2,525,983			3,805,441		3,271,276	245	237	237	237

	Source information									Calculations				
Company Name	**Plant Name**	**Unit ID**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**	**2004 Adjusted Heat Input**	**2005 Fuel Ratio**	**2005 Heat Input**	**2005 Adjusted Heat Input**	**Highest 2 year average**	**Calc'd CAIR**	**Adjusted 2010 CAIR**	**Corrected (Rounding) 2009**	**Corrected (Rounding) 2010**
Detroit Edison	Marysville	9			0			0		254,185	19	18	18	18
Detroit Edison	Marysville	10			0			0		203,429	15	15	15	15
Detroit Edison	Marysville	11			0			0		215,809	16	16	16	16
Detroit Edison	Marysville	12			0			0		258,536	19	19	19	19
Detroit Edison	Monroe	1			41,328,125			44,433,797		42,880,961	3,216	3,112	3,112	3,112
Detroit Edison	Monroe	2			39,069,142			37,320,815		42,360,547	3,177	3,074	3,074	3,074
Detroit Edison	Monroe	3			28,379,861			46,055,494		47,362,102	3,552	3,437	3,437	3,437
Detroit Edison	Monroe	4			49,753,246			48,732,751		52,519,554	3,939	3,811	3,811	3,811
Detroit Edison	River Rouge	1			18,092			58,024		644,144	19	19	19	19
Detroit Edison	River Rouge	2			17,182,775			15,915,215		17,855,631	1,339	1,296	1,296	1,296
Detroit Edison	River Rouge	3			17,245,980			12,365,866		16,603,172	1,245	1,205	1,205	1,205
Detroit Edison	St. Clair	1			9,024,092			8,297,906		9,051,602	679	657	657	657
Detroit Edison	St. Clair	2			9,145,258			8,434,530		9,569,330	718	694	694	694
Detroit Edison	St. Clair	3			7,040,417			8,209,177		9,102,577	683	661	661	661
Detroit Edison	St. Clair	4			7,241,706			9,583,774		9,594,237	720	696	696	696
Detroit Edison	St. Clair	6			19,239,917			17,931,580		18,585,749	1,394	1,349	1,349	1,349
Detroit Edison	St. Clair	7			25,930,296			23,592,556		26,009,497	1,951	1,888	1,888	1,888
Detroit Edison	Trenton Channel	16			5,155,720			4,337,513		4,762,905	357	346	346	346
Detroit Edison	Trenton Channel	17			4,801,287			4,410,672		4,605,980	345	334	334	334
Detroit Edison	Trenton Channel	18			4,943,593			4,027,943		4,637,500	348	337	337	337
Detroit Edison	Trenton Channel	19			4,955,719			4,193,209		4,682,267	351	340	340	340
Detroit Edison	Trenton Channel	9A			27,463,430			27,170,088		29,030,756	2,177	2,107	2,107	2,107
Detroit PLD	Mistersky	5			3,666,011			1,625,181		3,563,411	107	103	103	103
Detroit PLD	Mistersky	6			267,086			2,292,907		2,716,602	81	79	79	79
Detroit PLD	Mistersky	7			2,728,105			2,841,319		4,039,069	121	117	117	117
Detroit PLD	Mistersky	GT-1			34,163			27,442		107,856	5	5	5	5
Dynegy	Renaissance	CT1			554,974			1,129,782		985,589	28	27	27	27
Dynegy	Renaissance	CT2			61,334			1,045,517		880,660	25	24	24	24
Dynegy	Renaissance	CT3			89,798			1,490,111		861,436	25	24	24	24
Dynegy	Renaissance	CT4			91,559			1,540,285		1,105,262	32	31	31	31
FirstEnergy Genco	Sumpter	1			63,531			391,675		421,923	17	16	16	16
FirstEnergy Genco	Sumpter	2			57,361			412,947		402,959	16	16	16	16
FirstEnergy Genco	Sumpter	3			61,233			402,273		400,817	16	16	16	16
FirstEnergy Genco	Sumpter	4			56,513			427,602		432,811	17	17	17	17
Grand Haven BLP	Sims	3			3,497,186			4,576,267		4,470,734	335	324	324	324
Holland BPW	48th Street	7			87,520			60,364		230,984	7	7	7	7
Holland BPW	48th Street	8			8,012			39,430		77,098	2	2	2	2
Holland BPW	48th Street	9			171,618			99,726		556,192	20	19	19	19
Holland BPW	De Young	5			1,996,348			1,923,751		2,307,180	173	167	167	167
Kinder Morgan	Jackson Power	7EA			100,155			820,209		891,848	21	20	20	20
Kinder Morgan	Jackson Power	LM1			47,821			200,621		310,094	11	11	11	11
Kinder Morgan	Jackson Power	LM2			51,946			220,775		314,136	11	11	11	11
Kinder Morgan	Jackson Power	LM3			31,916			272,143		267,814	9	9	9	9
Kinder Morgan	Jackson Power	LM4			44,937			203,757		301,354	11	10	10	10
Kinder Morgan	Jackson Power	LM5			37,494			285,472		347,728	12	12	12	12
Kinder Morgan	Jackson Power	LM6			34,751			219,895		302,662	11	10	10	10
Lansing BWL	Eckert Station	1			2,234,063			2,670,370		2,702,758	203	196	196	196
Lansing BWL	Eckert Station	2			2,786,797			2,620,806		2,703,802	203	196	196	196
Lansing BWL	Eckert Station	3			2,826,199			2,945,059		2,980,297	224	216	216	216
Lansing BWL	Eckert Station	4			4,850,228			3,146,285		5,498,473	412	399	399	399
Lansing BWL	Eckert Station	5			5,181,326			3,953,871		5,195,875	390	377	377	377
Lansing BWL	Eckert Station	6			4,918,205			5,312,448		5,165,255	387	375	375	375
Lansing BWL	Erickson	1			8,880,260			11,920,080		10,912,871	818	792	792	792
Marquette. City of	Shiras	3			3,387,485			3,500,784		3,845,310	288	279	279	279
Michigan Power LP	MI Power LP	G101			9,784,452			10,357,229		10,193,451	280	271	271	271
Michigan Public Pwr	Kalkaska CT #1	1A			88,499			35,209		67,504	3	2	2	2
Michigan Public Pwr	Kalkaska CT #1	1B			70,999			45,072		63,037	2	2	2	2
Midland Cogen V.	Midland Cogen V.	GT10			8,111,834			**3,632,000**		7,180,164	215	208	208	208
Midland Cogen V.	Midland Cogen V.	GT11			8,276,253			**3,097,543**		7,573,654	227	220	220	220
Midland Cogen V.	Midland Cogen V.	GT12			7,212,935			**2,351,798**		6,793,379	340	329	329	329

	Source information									Calculations				
Company Name	**Plant Name**	**Unit ID**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**	**2004 Adjusted Heat Input**	**2005 Fuel Ratio**	**2005 Heat Input**	**2005 Adjusted Heat Input**	**Highest 2 year average**	**Calc'd CAIR**	**Adjusted 2010 CAIR**	**Corrected (Rounding) 2009**	**Corrected (Rounding) 2010**
Midland Cogen V.	Midland Cogen V.	GT13			7,474,816			**5,822,636**		7,376,680	221	214	214	214
Midland Cogen V.	Midland Cogen V.	GT14			6,927,472			**6,958,488**		6,942,980	208	202	202	202
Midland Cogen V.	Midland Cogen V.	GT3			8,146,665			**7,130,236**		7,886,542	237	229	229	229
Midland Cogen V.	Midland Cogen V.	GT4			7,461,836			**6,000,346**		7,394,062	222	215	215	215
Midland Cogen V.	Midland Cogen V.	GT5			6,981,125			**5,120,373**		6,605,241	198	192	192	192
Midland Cogen V.	Midland Cogen V.	GT6			7,300,661			**6,524,064**		7,108,374	213	206	206	206
Midland Cogen V.	Midland Cogen V.	GT7			8,335,206			**4,839,798**		7,488,024	225	217	217	217
Midland Cogen V.	Midland Cogen V.	GT8			8,290,856			**3,462,938**		7,978,940	239	232	232	232
Midland Cogen V.	Midland Cogen V.	GT9			7,879,375			**3,706,338**		7,274,863	218	211	211	211
Mirant Zeeland	Zeeland Power	1			21,509			319,883		614,254	15	15	15	15
Mirant Zeeland	Zeeland Power	2			46,340			245,681		578,578	14	14	14	14
Mirant Zeeland	Zeeland Power	3			777,561			2,368,447		1,843,698	34	33	33	33
Mirant Zeeland	Zeeland Power	4			564,348			2,588,067		1,879,294	34	33	33	33
MSCPA	Enidcott Gen St	1			5,447,333			6,321,768		5,884,551	441	427	427	427
WE Energies	Presque Isle	2			493,179			649,913		764,155	57	55	55	55
WE Energies	Presque Isle	3			3,848,254			3,894,294		3,871,274	290	281	281	281
WE Energies	Presque Isle	4			4,161,716			4,348,069		4,259,121	319	309	309	309
WE Energies	Presque Isle	5			5,700,616			5,817,350		5,950,887	446	432	432	432
WE Energies	Presque Isle	6			5,437,202			5,358,834		6,003,397	450	436	436	436
WE Energies	Presque Isle	7			5,506,930			7,309,610		6,845,598	513	497	497	497
WE Energies	Presque Isle	8			6,707,966			6,260,422		6,617,646	496	480	480	480
WE Energies	Presque Isle	9			6,569,457			6,397,620		6,550,216	491	475	475	475
Wyandotte DMS	Wyandotte	5			0			0		164,310	5	5	5	5
Wyandotte DMS	Wyandotte	7			2,535,120			2,780,422		2,657,771	199	193	193	193
Wyandotte DMS	Wyandotte	8			1,603,407			1,869,950		1,736,679	130	126	126	126
Corrections to the numbers include rounding up if greater tha											**65,216**	**63,104**	**63,104**	**63,104**

Source information			
Company Name	Plant Name	Unit ID	Corrected (Rounding) 2011
Cadillac RE	Cadillac Renew	GEN1	259
CMS Gen/MI Pwr	Kalamazoo River	1	4
CMS Gen/MI Pwr	Livingston Station	001	2
CMS Gen/MI Pwr	Livingston Station	002	2
CMS Gen/MI Pwr	Livingston Station	003	2
CMS Gen/MI Pwr	Livingston Station	004	2
CMS Generation	Genesee Power	GEN1	273
CMS Generation	Grayling Station	GEN1	273
CMS Generation	TES Filer City	B1	219
CMS Generation	TES Filer City	B2	219
Consumers Energy	Campbell	1	1,566
Consumers Energy	Campbell	2	1,758
Consumers Energy	Campbell	3	4,703
Consumers Energy	Cobb	1	8
Consumers Energy	Cobb	2	7
Consumers Energy	Cobb	3	7
Consumers Energy	Cobb	4	882
Consumers Energy	Cobb	5	952
Consumers Energy	Karn	1	1,425
Consumers Energy	Karn	2	1,465
Consumers Energy	Karn	3	260
Consumers Energy	Karn	4	200
Consumers Energy	Thetford CT	1	2
Consumers Energy	Thetford CT	2	2
Consumers Energy	Thetford CT	3	2
Consumers Energy	Thetford CT	4	2
Consumers Energy	Weadock	7	909
Consumers Energy	Weadock	8	971
Consumers Energy	Whiting	1	647
Consumers Energy	Whiting	2	654
Consumers Energy	Whiting	3	762
Covert Generating LLC	Covert	1	32
Covert Generating LLC	Covert	2	62
Covert Generating LLC	Covert	3	37
Dearborn Ind. Gen.	Dearborn Ind.	B1	126
Dearborn Ind. Gen.	Dearborn Ind.	B2	121
Dearborn Ind. Gen.	Dearborn Ind.	B3	127
Dearborn Ind. Gen.	Dearborn Ind.	GTP1	30
Detroit Edison	Belle River	1	3,902
Detroit Edison	Belle River	2	3,593
Detroit Edison	Belle River	CTG121	17
Detroit Edison	Belle River	CTG122	14
Detroit Edison	Belle River	CTG131	13
Detroit Edison	Connors Creek	15	10
Detroit Edison	Connors Creek	16	9
Detroit Edison	Connors Creek	17	8
Detroit Edison	Connors Creek	18	9
Detroit Edison	Delray	CTG111	10
Detroit Edison	Delray	CTG121	11
Detroit Edison	East China	1	4
Detroit Edison	East China	2	4
Detroit Edison	East China	3	4
Detroit Edison	East China	4	4
Detroit Edison	Greenwood	1	145
Detroit Edison	Greenwood	CTG111	13
Detroit Edison	Greenwood	CTG112	12
Detroit Edison	Greenwood	CTG121	9
Detroit Edison	Hancock	12-1 (5)	2
Detroit Edison	Hancock	12-2 (6)	1
Detroit Edison	Harbor Beach	1	237

Source information			
Company Name	Plant Name	Unit ID	Corrected (Rounding) 2011
Detroit Edison	Marysville	9	18
Detroit Edison	Marysville	10	15
Detroit Edison	Marysville	11	16
Detroit Edison	Marysville	12	19
Detroit Edison	Monroe	1	3,112
Detroit Edison	Monroe	2	3,074
Detroit Edison	Monroe	3	3,437
Detroit Edison	Monroe	4	3,811
Detroit Edison	River Rouge	1	19
Detroit Edison	River Rouge	2	1,296
Detroit Edison	River Rouge	3	1,205
Detroit Edison	St. Clair	1	657
Detroit Edison	St. Clair	2	694
Detroit Edison	St. Clair	3	661
Detroit Edison	St. Clair	4	696
Detroit Edison	St. Clair	6	1,349
Detroit Edison	St. Clair	7	1,888
Detroit Edison	Trenton Channel	16	346
Detroit Edison	Trenton Channel	17	334
Detroit Edison	Trenton Channel	18	337
Detroit Edison	Trenton Channel	19	340
Detroit Edison	Trenton Channel	9A	2,107
Detroit PLD	Mistersky	5	103
Detroit PLD	Mistersky	6	79
Detroit PLD	Mistersky	7	117
Detroit PLD	Mistersky	GT-1	5
Dynegy	Renaissance	CT1	27
Dynegy	Renaissance	CT2	24
Dynegy	Renaissance	CT3	24
Dynegy	Renaissance	CT4	31
FirstEnergy Genco	Sumpter	1	16
FirstEnergy Genco	Sumpter	2	16
FirstEnergy Genco	Sumpter	3	16
FirstEnergy Genco	Sumpter	4	17
Grand Haven BLP	Sims	3	324
Holland BPW	48th Street	7	7
Holland BPW	48th Street	8	2
Holland BPW	48th Street	9	19
Holland BPW	De Young	5	167
Kinder Morgan	Jackson Power	7EA	20
Kinder Morgan	Jackson Power	LM1	11
Kinder Morgan	Jackson Power	LM2	11
Kinder Morgan	Jackson Power	LM3	9
Kinder Morgan	Jackson Power	LM4	10
Kinder Morgan	Jackson Power	LM5	12
Kinder Morgan	Jackson Power	LM6	10
Lansing BWL	Eckert Station	1	196
Lansing BWL	Eckert Station	2	196
Lansing BWL	Eckert Station	3	216
Lansing BWL	Eckert Station	4	399
Lansing BWL	Eckert Station	5	377
Lansing BWL	Eckert Station	6	375
Lansing BWL	Erickson	1	792
Marquette. City of	Shiras	3	279
Michigan Power LP	MI Power LP	G101	271
Michigan Public Pwr	Kalkaska CT #1	1A	2
Michigan Public Pwr	Kalkaska CT #1	1B	2
Midland Cogen V.	Midland Cogen V.	GT10	208
Midland Cogen V.	Midland Cogen V.	GT11	220
Midland Cogen V.	Midland Cogen V.	GT12	329

Source information			
Company Name	**Plant Name**	**Unit ID**	**Corrected (Rounding) 2011**
Midland Cogen V.	Midland Cogen V.	GT13	214
Midland Cogen V.	Midland Cogen V.	GT14	202
Midland Cogen V.	Midland Cogen V.	GT3	229
Midland Cogen V.	Midland Cogen V.	GT4	215
Midland Cogen V.	Midland Cogen V.	GT5	192
Midland Cogen V.	Midland Cogen V.	GT6	206
Midland Cogen V.	Midland Cogen V.	GT7	217
Midland Cogen V.	Midland Cogen V.	GT8	232
Midland Cogen V.	Midland Cogen V.	GT9	211
Mirant Zeeland	Zeeland Power	1	15
Mirant Zeeland	Zeeland Power	2	14
Mirant Zeeland	Zeeland Power	3	33
Mirant Zeeland	Zeeland Power	4	33
MSCPA	Enidcott Gen St	1	427
WE Energies	Presque Isle	2	55
WE Energies	Presque Isle	3	281
WE Energies	Presque Isle	4	309
WE Energies	Presque Isle	5	432
WE Energies	Presque Isle	6	436
WE Energies	Presque Isle	7	497
WE Energies	Presque Isle	8	480
WE Energies	Presque Isle	9	475
Wyandotte DMS	Wyandotte	5	5
Wyandotte DMS	Wyandotte	7	193
Wyandotte DMS	Wyandotte	8	126
Corrections to the numbers include rounding up if greater tha			**63,104**

	Source information		Operations Data										Ozone Season Values					
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-14**	**Fuel Adj Factor**	**Arith. Ave.**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**
Cadillac RE	Cadillac Renew	GEN1	solid		0.15	1.00			1,567,395			1,425,980			1,382,867			1,429,064
CMS Gen/MI Pwr	Kalamazoo River	1	gas	**0.085**	0.15	0.40	**0.07**		15,852			9,065			23,332			57,415
CMS Gen/MI Pwr	Livingston Station	001	gas		0.15	0.40			36,183			10,364			21,187			17,436
CMS Gen/MI Pwr	Livingston Station	002	gas		0.15	0.40			34,314			11,323			22,562			16,274
CMS Gen/MI Pwr	Livingston Station	003	gas		0.15	0.40			33,363			14,140			21,436			7,605
CMS Gen/MI Pwr	Livingston Station	004	gas		0.15	0.40			34,952			8,070			21,498			16,378
CMS Generation	Genesee Power	GEN1	solid		0.15	1.00			1,475,225			1,372,514			1,292,849			1,241,432
CMS Generation	Grayling Station	GEN1	solid		0.15	1.00			1,543,980			1,201,820			1,346,391			1,638,608
CMS Generation	TES Filer City	B1	solid		0.15	1.00			1,336,192			1,106,298			1,156,981			1,372,265
CMS Generation	TES Filer City	B2	solid		0.15	1.00			1,336,192			1,106,298			1,156,981			1,372,265
Consumers Energy	Campbell	1	solid		0.15	1.00			5,825,632			9,656,016			9,264,652			9,129,636
Consumers Energy	Campbell	2	solid		0.15	1.00			9,766,936			10,786,454			9,478,872			8,587,536
Consumers Energy	Campbell	3	solid		0.15	1.00			27,634,659			25,298,815			26,346,455			21,541,781
Consumers Energy	Cobb	1	gas		0.15	0.40			238,349			176,489			47,190			295
Consumers Energy	Cobb	2	gas		0.15	0.40			219,116			164,021			47,935			227
Consumers Energy	Cobb	3	gas		0.15	0.40			269,215			179,793			7,820			133
Consumers Energy	Cobb	4	solid		0.15	1.00			5,067,731			4,901,417			5,014,409			5,168,580
Consumers Energy	Cobb	5	solid		0.15	1.00			5,133,332			5,748,538			5,462,145			5,388,204
Consumers Energy	Karn	1	solid		0.15	1.00			7,939,290			8,153,810			7,318,814			9,020,947
Consumers Energy	Karn	2	solid		0.15	1.00			8,784,336			8,192,913			8,530,178			8,706,408
Consumers Energy	Karn	3	dual		0.15	0.40		0.48	5,430,089	2,602,501	0.49	5,170,520	2,540,792	0.55	2,218,160	1,212,244	0.57	1,855,805
Consumers Energy	Karn	4	dual		0.15	0.40		0.48	4,881,440	2,326,589	0.50	2,936,278	1,476,536	0.54	1,434,765	776,276	0.58	925,404
Consumers Energy	Thetford CT	1	gas		0.15	0.40			16,419			8,057			5,286			5,097
Consumers Energy	Thetford CT	2	gas		0.15	0.40			13,187			7,135			5,138			9,062
Consumers Energy	Thetford CT	3	gas		0.15	0.40			11,900			8,192			3,289			5,884
Consumers Energy	Thetford CT	4	gas		0.15	0.40			5,791			7,160			3,384			5,318
Consumers Energy	Weadock	7	solid		0.15	1.00			4,348,739			5,018,497			5,452,648			2,116,732
Consumers Energy	Weadock	8	solid		0.15	1.00			6,069,066			5,199,624			5,008,404			4,898,151
Consumers Energy	Whiting	1	solid		0.15	1.00			3,599,715			3,822,763			3,869,579			3,325,270
Consumers Energy	Whiting	2	solid		0.15	1.00			3,813,878			3,541,774			3,159,438			3,340,050
Consumers Energy	Whiting	3	solid		0.15	1.00			3,546,075			4,574,997			4,238,361			4,422,438
Covert Generating LLC	Covert	1	gas	**0.009**	0.15	0.40	**0.03**		0			0			371,134			273,364
Covert Generating LLC	Covert	2	gas	**0.009**	0.15	0.40	**0.03**		0			0			1,005,724			326,686
Covert Generating LLC	Covert	3	gas	**0.009**	0.15	0.40	**0.03**		0			0			0			732,023
Dearborn Ind. Gen.	Dearborn Ind.	B1	gas	**0.1**	0.15	0.40	**0.08**		593,471			937,146			856,681			1,079,255
Dearborn Ind. Gen.	Dearborn Ind.	B2	gas	**0.1**	0.15	0.40	**0.08**		546,149			795,476			750,113			989,029
Dearborn Ind. Gen.	Dearborn Ind.	B3	gas	**0.1**	0.15	0.40	**0.08**		400,740			967,910			627,718			1,061,786
Dearborn Ind. Gen.	Dearborn Ind.	GTP1	gas	**0.033**	0.15	0.40	**0.05**		381,690			541,442			62,856			187,512
Detroit Edison	Belle River	1	solid		0.15	1.00			21,092,846			23,555,397			20,612,325			18,214,949
Detroit Edison	Belle River	2	solid		0.15	1.00			20,908,556			17,421,262			18,978,701			19,781,320
Detroit Edison	Belle River	CTG121	gas	**0.033**	0.15	0.40	**0.05**		324,049			468,998			172,368			97,269
Detroit Edison	Belle River	CTG122	gas	**0.033**	0.15	0.40	**0.05**		281,535			413,928			133,262			78,801
Detroit Edison	Belle River	CTG131	gas	**0.033**	0.15	0.40	**0.05**		271,184			233,234			149,075			62,515
Detroit Edison	Connors Creek	15	gas		0.15	0.40			264,972			246,262			102,378			146,271
Detroit Edison	Connors Creek	16	gas		0.15	0.40			276,197			207,173			74,398			104,645
Detroit Edison	Connors Creek	17	gas		0.15	0.40			236,651			146,908			99,776			142,950
Detroit Edison	Connors Creek	18	gas		0.15	0.40			265,491			188,754			83,168			131,750
Detroit Edison	Delray	CTG111	gas	**0.055**	0.15	0.40	**0.06**		147,755			285,147			101,493			81,174
Detroit Edison	Delray	CTG121	gas	**0.055**	0.15	0.40	**0.06**		143,171			270,643			84,738			100,543
Detroit Edison	East China	1	gas	**0.036**	0.15	0.40	**0.05**		0			45,663			90,022			0
Detroit Edison	East China	2	gas	**0.036**	0.15	0.40	**0.05**		0			45,653			93,866			0
Detroit Edison	East China	3	gas	**0.036**	0.15	0.40	**0.05**		0			45,266			91,329			0
Detroit Edison	East China	4	gas	**0.036**	0.15	0.40	**0.05**		0			42,601			92,771			0
Detroit Edison	Greenwood	1	dual		0.15	0.40		0.46	4,353,727	2,007,664	0.48	5,891,835	2,851,036	0.49	2,941,199	1,435,819	0.53	2,850,058
Detroit Edison	Greenwood	CTG111	gas	**0.033**	0.15	0.40	**0.05**		247,443			303,921			102,717			17,393
Detroit Edison	Greenwood	CTG112	gas	**0.033**	0.15	0.40	**0.05**		229,920			340,061			72,515			17,865
Detroit Edison	Greenwood	CTG121	gas	**0.033**	0.15	0.40	**0.05**		208,006			307,478			82,515			15,640
Detroit Edison	Hancock	12-1 (5)	gas		0.15	0.40			36,296			11,731			13,584			6,585
Detroit Edison	Hancock	12-2 (6)	gas		0.15	0.40			32,774			14,880			13,984			6,108
Detroit Edison	Harbor Beach	1	solid		0.15	1.00			908,138			1,409,137			930,856			908,046
Detroit Edison	Marysville	9	solid		0.15	1.00			233,240			0			0			0

	Source information		Operations Data									Ozone Season Values						
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-14**	**Fuel Adj Factor**	**Arith. Ave.**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**
Detroit Edison	Marysville	10	solid		0.15	1.00			193,046			0			0			0
Detroit Edison	Marysville	11	solid		0.15	1.00			260,964			0			0			0
Detroit Edison	Marysville	12	solid		0.15	1.00			258,445			0			0			0
Detroit Edison	Monroe	1	solid		0.15	1.00			17,494,384			18,596,466			15,073,173			16,557,060
Detroit Edison	Monroe	2	solid		0.15	1.00			16,690,339			18,828,555			14,858,228			15,715,116
Detroit Edison	Monroe	3	solid		0.15	1.00			21,489,324			15,733,177			16,431,859			12,806,092
Detroit Edison	Monroe	4	solid		0.15	1.00			20,854,415			16,089,941			25,444,852			19,562,301
Detroit Edison	River Rouge	1	gas		0.15	0.40			734,911			549,025			252,639			18,092
Detroit Edison	River Rouge	2	solid		0.15	1.00			4,422,619			7,791,035			6,867,920			6,828,431
Detroit Edison	River Rouge	3	solid		0.15	1.00			7,918,497			7,204,611			5,297,685			6,940,095
Detroit Edison	St. Clair	1	solid		0.15	1.00			3,402,797			3,787,656			2,847,462			3,940,939
Detroit Edison	St. Clair	2	solid		0.15	1.00			4,445,613			3,033,858			2,274,844			4,163,962
Detroit Edison	St. Clair	3	solid		0.15	1.00			3,022,297			4,556,164			3,914,288			3,486,917
Detroit Edison	St. Clair	4	solid		0.15	1.00			3,790,539			4,082,900			3,640,161			3,524,985
Detroit Edison	St. Clair	6	solid		0.15	1.00			8,240,084			7,764,080			7,777,085			7,669,330
Detroit Edison	St. Clair	7	solid		0.15	1.00			7,368,393			11,284,581			10,049,199			11,355,886
Detroit Edison	Trenton Channel	16	solid		0.15	1.00			1,622,536			1,587,597			1,633,487			2,106,205
Detroit Edison	Trenton Channel	17	solid		0.15	1.00			1,814,026			1,617,612			1,724,274			1,962,086
Detroit Edison	Trenton Channel	18	solid		0.15	1.00			1,812,309			1,691,132			1,370,815			1,974,104
Detroit Edison	Trenton Channel	19	solid		0.15	1.00			1,992,713			1,682,477			1,565,822			1,871,634
Detroit Edison	Trenton Channel	9A	solid		0.15	1.00			11,376,671			12,886,689			12,551,960			11,544,193
Detroit PLD	Mistersky	5	gas		0.15	0.40			598,881			1,661,025			1,276,430			1,597,254
Detroit PLD	Mistersky	6	gas		0.15	0.40			1,794,436			0			0			0
Detroit PLD	Mistersky	7	gas		0.15	0.40			2,392,548			1,049,466			1,060,243			810,625
Detroit PLD	Mistersky	GT-1	liquid		0.15	0.60			0			0			102,216			10,522
Dynegy	Renaissance	CT1	gas	**0.055**	0.15	0.40	**0.06**		0			731,088			242,131			539,088
Dynegy	Renaissance	CT2	gas	**0.055**	0.15	0.40	**0.06**		0			630,495			248,336			60,351
Dynegy	Renaissance	CT3	gas	**0.055**	0.15	0.40	**0.06**		0			0			231,850			89,086
Dynegy	Renaissance	CT4	gas	**0.055**	0.15	0.40	**0.06**		0			589,651			200,584			90,756
FirstEnergy Genco	Sumpter	1	gas	**0.1**	0.15	0.40	**0.08**		0			406,060			150,452			38,905
FirstEnergy Genco	Sumpter	2	gas	**0.1**	0.15	0.40	**0.08**		0			347,284			161,778			42,030
FirstEnergy Genco	Sumpter	3	gas	**0.1**	0.15	0.40	**0.08**		0			353,473			155,869			38,631
FirstEnergy Genco	Sumpter	4	gas	**0.1**	0.15	0.40	**0.08**		0			392,267			119,315			48,182
Grand Haven BLP	Sims	3	solid		0.15	1.00			1,913,831			1,298,809			1,523,167			1,454,537
Holland BPW	48th Street	7	gas		0.15	0.40			124,516			235,579			41,111			72,527
Holland BPW	48th Street	8	gas		0.15	0.40			44,613			89,537			52,342			5,338
Holland BPW	48th Street	9	gas	**0.081**	0.15	0.40	**0.07**		358,387			591,954			199,981			122,340
Holland BPW	De Young	5	solid		0.15	1.00			948,165			803,750			938,115			792,040
Kinder Morgan	Jackson Power	7EA	gas	**0.033**	0.15	0.40	**0.05**		0			908,903			227,749			73,992
Kinder Morgan	Jackson Power	LM1	gas	**0.081**	0.15	0.40	**0.07**		0			407,843			91,180			40,383
Kinder Morgan	Jackson Power	LM2	gas	**0.081**	0.15	0.40	**0.07**		0			385,944			86,062			38,188
Kinder Morgan	Jackson Power	LM3	gas	**0.081**	0.15	0.40	**0.07**		0			237,704			85,070			24,192
Kinder Morgan	Jackson Power	LM4	gas	**0.081**	0.15	0.40	**0.07**		0			387,859			81,548			41,628
Kinder Morgan	Jackson Power	LM5	gas	**0.081**	0.15	0.40	**0.07**		0			388,691			86,957			33,267
Kinder Morgan	Jackson Power	LM6	gas	**0.081**	0.15	0.40	**0.07**		0			365,514			85,492			27,699
Lansing BWL	Eckert Station	1	solid		0.15	1.00			1,176,193			1,026,237			1,102,483			821,432
Lansing BWL	Eckert Station	2	solid		0.15	1.00			1,185,395			1,074,194			846,646			1,111,663
Lansing BWL	Eckert Station	3	solid		0.15	1.00			964,397			1,287,915			993,046			1,279,568
Lansing BWL	Eckert Station	4	solid		0.15	1.00			2,367,356			2,385,076			2,203,249			2,077,331
Lansing BWL	Eckert Station	5	solid		0.15	1.00			2,165,973			1,849,618			2,013,729			1,831,203
Lansing BWL	Eckert Station	6	solid		0.15	1.00			2,032,492			2,096,183			2,337,225			2,054,909
Lansing BWL	Erickson	1	solid		0.15	1.00			3,693,555			4,577,260			4,400,621			5,261,478
Marquette. City of	Shiras	3	solid		0.15	1.00			1,518,405			1,551,934			1,561,098			1,436,504
Michigan Power LP	MI Power LP	G101	gas	**0.05**	0.15	0.40	**0.06**		3,234,374			3,958,110			4,195,664			4,226,229
Michigan Public Pwr	Kalkaska CT #1	1A	gas	**0.092**	0.15	0.40	**0.08**		0			0			37,050			25,061
Michigan Public Pwr	Kalkaska CT #1	1B	gas	**0.092**	0.15	0.40	**0.08**		0			0			43,174			16,173
Midland Cogen V.	Midland Cogen V.	GT10	gas		0.15	0.40			2,835,697			2,942,063			1,846,749			3,316,802
Midland Cogen V.	Midland Cogen V.	GT11	gas		0.15	0.40			2,946,020			2,780,781			2,357,288			3,469,205
Midland Cogen V.	Midland Cogen V.	GT12	gas	**0.14**	0.15	0.40	**0.10**		2,967,937			2,590,448			2,208,821			2,873,082
Midland Cogen V.	Midland Cogen V.	GT13	gas		0.15	0.40			3,429,136			2,602,609			2,402,116			3,449,706
Midland Cogen V.	Midland Cogen V.	GT14	gas		0.15	0.40			2,785,723			2,769,489			2,051,354			3,430,409

	Source information		Operations Data									Ozone Season Values						
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-14**	**Fuel Adj Factor**	**Arith. Ave.**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**
Midland Cogen V.	Midland Cogen V.	GT3	gas		0.15	0.40			2,846,179			2,796,031			2,452,390			3,450,372
Midland Cogen V.	Midland Cogen V.	GT4	gas		0.15	0.40			2,844,802			2,617,087			2,005,539			3,076,638
Midland Cogen V.	Midland Cogen V.	GT5	gas		0.15	0.40			3,123,470			2,428,780			2,238,596			3,468,621
Midland Cogen V.	Midland Cogen V.	GT6	gas		0.15	0.40			2,662,165			2,817,748			2,302,016			2,802,132
Midland Cogen V.	Midland Cogen V.	GT7	gas		0.15	0.40			2,702,821			2,522,885			2,085,772			3,343,686
Midland Cogen V.	Midland Cogen V.	GT8	gas		0.15	0.40			3,415,266			2,714,763			1,907,860			3,386,642
Midland Cogen V.	Midland Cogen V.	GT9	gas		0.15	0.40			2,914,151			2,734,935			2,402,622			3,326,102
Mirant Zeeland	Zeeland Power	1	gas	**0.04**	0.15	0.40	**0.05**		526,271			429,514			86,239			0
Mirant Zeeland	Zeeland Power	2	gas	**0.04**	0.15	0.40	**0.05**		563,173			438,410			106,859			32,508
Mirant Zeeland	Zeeland Power	3	gas	**0.013**	0.15	0.40	**0.04**		0			1,059,959			635,189			746,197
Mirant Zeeland	Zeeland Power	4	gas	**0.013**	0.15	0.40	**0.04**		0			975,450			569,187			525,717
MSCPA	Enidcott Gen St	1	solid		0.15	1.00			2,138,461			2,370,990			2,434,400			2,393,181
WE Energies	Presque Isle	2	solid		0.15	1.00			232,161			47,268			23,213			283,672
WE Energies	Presque Isle	3	solid		0.15	1.00			1,296,693			1,625,166			872,400			1,495,516
WE Energies	Presque Isle	4	solid		0.15	1.00			1,612,406			1,000,893			1,462,741			1,526,912
WE Energies	Presque Isle	5	solid		0.15	1.00			2,603,708			2,697,695			2,061,455			2,230,869
WE Energies	Presque Isle	6	solid		0.15	1.00			2,400,204			1,883,125			1,747,689			2,422,967
WE Energies	Presque Isle	7	solid		0.15	1.00			2,793,953			3,041,844			2,304,342			2,933,879
WE Energies	Presque Isle	8	solid		0.15	1.00			2,887,178			2,849,343			2,735,688			3,033,454
WE Energies	Presque Isle	9	solid		0.15	1.00			2,785,068			2,868,513			2,270,262			2,721,706
Wyandotte DMS	Wyandotte	5	gas		0.150	0.40			8,198			132,486			0			0
Wyandotte DMS	Wyandotte	7	solid		0.15	1.00			1,171,251			873,374			1,045,593			1,053,653
Wyandotte DMS	Wyandotte	8	solid		0.150	1.00			759,822			612,706			564,754			758,939

Corrections to the numbers: rounding up if >0.5

Source information							Calculations				
Company Name	**Plant Name**	**Unit ID**	**2004 Adjusted Heat Input**	**2005 Fuel Ratio**	**2005 Heat Input**	**2005 Adjusted Heat Input**	**Highest 2 year ave**	**Calculated CAIR**	**Adjusted CAIR**	**Corrected (Rounding) 2010**	**Corrected (Rounding) 2011**
Cadillac RE	Cadillac Renew	GEN1			1517985		1,542,690	116	114	114	114
CMS Gen/MI Pwr	Kalamazoo River	1			164,296		110,856	4	4	4	4
CMS Gen/MI Pwr	Livingston Station	001			89,307		62,745	2	2	2	2
CMS Gen/MI Pwr	Livingston Station	002			91,409		62,862	2	2	2	2
CMS Gen/MI Pwr	Livingston Station	003			108,419		70,891	2	2	2	2
CMS Gen/MI Pwr	Livingston Station	004			91,425		63,189	2	2	2	2
CMS Generation	Genesee Power	GEN1			1,708,417		1,591,821	119	118	118	118
CMS Generation	Grayling Station	GEN1			1,477,159		1,591,294	119	118	118	118
CMS Generation	TES Filer City	B1			1,170,467		1,354,229	102	100	100	100
CMS Generation	TES Filer City	B2			1,170,467		1,354,229	102	100	100	100
Consumers Energy	Campbell	1			8,818,479		9,460,334	710	700	700	700
Consumers Energy	Campbell	2			10,363,932		10,575,193	793	782	782	782
Consumers Energy	Campbell	3			24,446,249		26,990,557	2,024	1,997	1,997	1,997
Consumers Energy	Cobb	1			241,779		240,064	7	7	7	7
Consumers Energy	Cobb	2			231,899		225,508	7	7	7	7
Consumers Energy	Cobb	3			209,770		239,493	7	7	7	7
Consumers Energy	Cobb	4			4,737,228		5,118,156	384	379	379	379
Consumers Energy	Cobb	5			5,645,708		5,697,123	427	421	421	421
Consumers Energy	Karn	1			8,989,897		9,005,422	675	666	666	666
Consumers Energy	Karn	2			8,155,171		8,745,372	656	647	647	647
Consumers Energy	Karn	3	1,048,566	0.49	3,299,963	1,604,519	2,571,647	193	190	190	190
Consumers Energy	Karn	4	532,547	0.48	3,052,861	1,469,948	1,901,562	143	141	141	141
Consumers Energy	Thetford CT	1			67,514		41,967	1	1	1	1
Consumers Energy	Thetford CT	2			76,391		44,789	1	1	1	1
Consumers Energy	Thetford CT	3			81,011		46,456	1	1	1	1
Consumers Energy	Thetford CT	4			85,354		46,257	1	1	1	1
Consumers Energy	Weadock	7			4,908,421		5,235,573	393	387	387	387
Consumers Energy	Weadock	8			4,604,029		5,634,345	423	417	417	417
Consumers Energy	Whiting	1			3,687,576		3,846,171	288	285	285	285
Consumers Energy	Whiting	2			3,822,454		3,818,166	286	282	282	282
Consumers Energy	Whiting	3			3,421,845		4,498,718	337	333	333	333
Covert Generating LLC	Covert	1			1,868,854		1,119,994	19	19	19	19
Covert Generating LLC	Covert	2			2,113,179		1,559,452	27	27	27	27
Covert Generating LLC	Covert	3			1,977,411		1,354,717	23	23	23	23
Dearborn Ind. Gen.	Dearborn Ind.	B1			1,937,257		1,508,256	60	60	60	60
Dearborn Ind. Gen.	Dearborn Ind.	B2			2,017,352		1,503,191	60	59	59	59
Dearborn Ind. Gen.	Dearborn Ind.	B3			1,903,475		1,482,631	59	58	58	58
Dearborn Ind. Gen.	Dearborn Ind.	GTP1			1,428,166		984,804	23	23	23	23
Detroit Edison	Belle River	1			18,538,480		22,324,122	1,674	1,652	1,652	1,652
Detroit Edison	Belle River	2			19,900,880		20,404,718	1,530	1,510	1,510	1,510
Detroit Edison	Belle River	CTG121			430,834		449,916	10	10	10	10
Detroit Edison	Belle River	CTG122			431,154		422,541	10	10	10	10
Detroit Edison	Belle River	CTG131			422,589		346,887	8	8	8	8
Detroit Edison	Connors Creek	15			371,020		317,996	10	9	9	9
Detroit Edison	Connors Creek	16			317,496		296,847	9	9	9	9
Detroit Edison	Connors Creek	17			277,818		257,235	8	8	8	8
Detroit Edison	Connors Creek	18			319,128		292,310	9	9	9	9
Detroit Edison	Delray	CTG111			175,399		230,273	7	7	7	7
Detroit Edison	Delray	CTG121			269,442		270,043	8	8	8	8
Detroit Edison	East China	1			265,055		177,539	4	4	4	4
Detroit Edison	East China	2			271,955		182,911	4	4	4	4
Detroit Edison	East China	3			271,717		181,523	4	4	4	4
Detroit Edison	East China	4			247,276		170,024	4	4	4	4
Detroit Edison	Greenwood	1	1,517,902	0.48	5,413,305	2,619,477	2,735,256	205	202	202	202
Detroit Edison	Greenwood	CTG111			458,781		381,351	9	9	9	9
Detroit Edison	Greenwood	CTG112			458,718		399,390	9	9	9	9
Detroit Edison	Greenwood	CTG121			175,347		257,742	6	6	6	6
Detroit Edison	Hancock	12-1 (5)			19,770		28,033	1	1	1	1
Detroit Edison	Hancock	12-2 (6)			6,185		23,827	1	1	1	1
Detroit Edison	Harbor Beach	1			1,588,783		1,498,960	112	111	111	111
Detroit Edison	Marysville	9			0		116,620	9	9	9	9

Source information							Calculations				
Company Name	**Plant Name**	**Unit ID**	**2004 Adjusted Heat Input**	**2005 Fuel Ratio**	**2005 Heat Input**	**2005 Adjusted Heat Input**	**Highest 2 year ave**	**Calculated CAIR**	**Adjusted CAIR**	**Corrected (Rounding) 2010**	**Corrected (Rounding) 2011**
Detroit Edison	Marysville	10			0		96,523	7	7	7	7
Detroit Edison	Marysville	11			0		130,482	10	10	10	10
Detroit Edison	Marysville	12			0		129,223	10	10	10	10
Detroit Edison	Monroe	1			18,389,509		18,492,988	1,387	1,368	1,368	1,368
Detroit Edison	Monroe	2			19,300,902		19,064,729	1,430	1,410	1,410	1,410
Detroit Edison	Monroe	3			20,834,665		21,161,995	1,587	1,566	1,566	1,566
Detroit Edison	Monroe	4			21,031,547		23,238,200	1,743	1,719	1,719	1,719
Detroit Edison	River Rouge	1			55,402		641,968	19	19	19	19
Detroit Edison	River Rouge	2			6,211,562		7,329,478	550	542	542	542
Detroit Edison	River Rouge	3			5,617,052		7,561,554	567	559	559	559
Detroit Edison	St. Clair	1			3,658,570		3,864,298	290	286	286	286
Detroit Edison	St. Clair	2			3,477,329		4,304,788	323	318	318	318
Detroit Edison	St. Clair	3			3,514,244		4,235,226	318	313	313	313
Detroit Edison	St. Clair	4			3,832,335		3,957,618	297	293	293	293
Detroit Edison	St. Clair	6			7,174,177		8,008,585	601	592	592	592
Detroit Edison	St. Clair	7			9,087,177		11,320,234	849	837	837	837
Detroit Edison	Trenton Channel	16			1,696,304		1,901,255	143	141	141	141
Detroit Edison	Trenton Channel	17			1,634,175		1,888,056	142	140	140	140
Detroit Edison	Trenton Channel	18			1,636,050		1,893,207	142	140	140	140
Detroit Edison	Trenton Channel	19			1,642,589		1,932,174	145	143	143	143
Detroit Edison	Trenton Channel	9A			12,221,984		12,719,325	954	941	941	941
Detroit PLD	Mistersky	5			981,641		1,629,140	49	48	48	48
Detroit PLD	Mistersky	6			759,654		1,277,045	38	38	38	38
Detroit PLD	Mistersky	7			1,001,238		1,726,396	52	51	51	51
Detroit PLD	Mistersky	GT-1			27,442		64,829	3	3	3	3
Dynegy	Renaissance	CT1			874,373		802,731	23	23	23	23
Dynegy	Renaissance	CT2			637,468		633,982	18	18	18	18
Dynegy	Renaissance	CT3			1,049,165		640,508	18	18	18	18
Dynegy	Renaissance	CT4			1,115,844		852,748	25	24	24	24
FirstEnergy Genco	Sumpter	1			293,630		349,845	14	14	14	14
FirstEnergy Genco	Sumpter	2			295,387		321,336	13	13	13	13
FirstEnergy Genco	Sumpter	3			285,696		319,585	13	13	13	13
FirstEnergy Genco	Sumpter	4			285,632		338,950	14	13	13	13
Grand Haven BLP	Sims	3			2,123,814		2,018,823	151	149	149	149
Holland BPW	48th Street	7			21,126		180,048	5	5	5	5
Holland BPW	48th Street	8			33,238		70,940	2	2	2	2
Holland BPW	48th Street	9			80,517		475,171	17	17	17	17
Holland BPW	De Young	5			854,060		943,140	71	70	70	70
Kinder Morgan	Jackson Power	7EA			624,055		766,479	18	18	18	18
Kinder Morgan	Jackson Power	LM1			165,200		286,522	10	10	10	10
Kinder Morgan	Jackson Power	LM2			178,236		282,090	10	10	10	10
Kinder Morgan	Jackson Power	LM3			239,320		238,512	8	8	8	8
Kinder Morgan	Jackson Power	LM4			168,090		277,975	10	10	10	10
Kinder Morgan	Jackson Power	LM5			241,329		315,010	11	11	11	11
Kinder Morgan	Jackson Power	LM6			184,457		274,986	10	10	10	10
Lansing BWL	Eckert Station	1			1,075,204		1,139,338	85	84	84	84
Lansing BWL	Eckert Station	2			1,076,943		1,148,529	86	85	85	85
Lansing BWL	Eckert Station	3			1,157,985		1,283,742	96	95	95	95
Lansing BWL	Eckert Station	4			1,665,282		2,376,216	178	176	176	176
Lansing BWL	Eckert Station	5			1,940,193		2,089,851	157	155	155	155
Lansing BWL	Eckert Station	6			2,186,765		2,261,995	170	167	167	167
Lansing BWL	Erickson	1			4,638,331		4,949,905	371	366	366	366
Marquette. City of	Shiras	3			1,548,393		1,556,516	117	115	115	115
Michigan Power LP	MI Power LP	G101			4,160,198		4,210,947	116	114	114	114
Michigan Public Pwr	Kalkaska CT #1	1A			16,314		31,056	1	1	1	1
Michigan Public Pwr	Kalkaska CT #1	1B			23,548		33,361	1	1	1	1
Midland Cogen V.	Midland Cogen V.	GT10			**1,129,042**		3,129,433	94	93	93	93
Midland Cogen V.	Midland Cogen V.	GT11			**1,023,090**		3,207,613	96	95	95	95
Midland Cogen V.	Midland Cogen V.	GT12			**837,169**		2,920,510	146	144	144	144
Midland Cogen V.	Midland Cogen V.	GT13			**1,992,625**		3,439,421	103	102	102	102
Midland Cogen V.	Midland Cogen V.	GT14			**2,934,540**		3,182,475	95	94	94	94

Source information							Calculations				
Company Name	Plant Name	Unit ID	2004 Adjusted Heat Input	2005 Fuel Ratio	2005 Heat Input	2005 Adjusted Heat Input	Highest 2 year ave	Calculated CAIR	Adjusted CAIR	Corrected (Rounding) 2010	Corrected (Rounding) 2011
Midland Cogen V.	Midland Cogen V.	GT3			3,132,745		3,291,559	99	97	97	97
Midland Cogen V.	Midland Cogen V.	GT4			2,869,075		2,972,857	89	88	88	88
Midland Cogen V.	Midland Cogen V.	GT5			3,205,444		3,337,033	100	99	99	99
Midland Cogen V.	Midland Cogen V.	GT6			3,273,214		3,045,481	91	90	90	90
Midland Cogen V.	Midland Cogen V.	GT7			1,195,738		3,023,254	91	89	89	89
Midland Cogen V.	Midland Cogen V.	GT8			1,236,445		3,400,954	102	101	101	101
Midland Cogen V.	Midland Cogen V.	GT9			1,091,027		3,120,127	94	92	92	92
Mirant Zeeland	Zeeland Power	1			277,935		477,893	12	12	12	12
Mirant Zeeland	Zeeland Power	2			140,803		500,792	13	12	12	12
Mirant Zeeland	Zeeland Power	3			1,486,233		1,273,096	23	23	23	23
Mirant Zeeland	Zeeland Power	4			1,625,357		1,300,404	24	23	23	23
MSCPA	Enidcott Gen St	1			2,939,389		2,686,895	202	199	199	199
WE Energies	Presque Isle	2			424,944		354,308	27	26	26	26
WE Energies	Presque Isle	3			2,072,168		1,848,667	139	137	137	137
WE Energies	Presque Isle	4			1,688,378		1,650,392	124	122	122	122
WE Energies	Presque Isle	5			2,442,717		2,650,702	199	196	196	196
WE Energies	Presque Isle	6			2,303,735		2,411,586	181	178	178	178
WE Energies	Presque Isle	7			3,203,683		3,122,764	234	231	231	231
WE Energies	Presque Isle	8			2,706,456		2,960,316	222	219	219	219
WE Energies	Presque Isle	9			2,798,186		2,833,350	213	210	210	210
Wyandotte DMS	Wyandotte	5			0		70,342	2	2	2	2
Wyandotte DMS	Wyandotte	7			1,231,637		1,201,444	90	89	89	89
Wyandotte DMS	Wyandotte	8			920,942		840,382	63	62	62	62
Corrections to the numbers: rounding up if >0.5								**28,711**	**28,321**	**28,321**	**28,321**

Michigan Non EGUs Ozone Season

Company Name	SRN	Unit ID	Name Plate Capacity in mmBtu	County	Emission Factor	2001 Heat Input	2002 Heat Input	2003 Heat Input	2004 Heat Input	2005 Heat Input	Highest 2 year ave.	CAIR Allow	Adjusted CAIR 2010	Corrected (Rounding) CAIR 2010	Corrected (Rounding) CAIR 2011
CE - Karn_Weadock	B2840	A	300	Bay	0.17	61,855	27,750	23,859	24,640	47,738	54,797	5	9	9	9
CE - Karn_Weadock	B2840	B	300	Bay	0.17	77,086	54,657	20,570	29,235	60,886	68,986	6	12	12	12
Dearborn Ind. Gen.	N6631	GT21	1562	Wayne	**0.03**	2,956,150	3,849,500	755,800	1,978,000	1,700,445	3,402,825	56	112	112	112
Dearborn Ind. Gen.	N6631	GT31	1562	Wayne	**0.03**	2,560,600	2,855,100	1,075,300	1,544,800	1,950,156	2,707,850	45	89	89	89
Dow Chemical USA	A4033	0401	300	Midland	0.17	8,100	21,935	4,755	2,728	1,362	15,017	1	3	5	5
Dow Chemical USA	A4033	0402	300	Midland	0.17	7,115	21,626	3,428	3,418	1,357	14,370	1	2	4	4
Graphics Pkg.	B1678	0003	253	Kalamazoo	0.17	753,521	462,844	753,095	642,279	630,034	753,308	64	128	128	128
Lansing BW&L	B2647	0014	290	Ingham	0.17	345,726	20,554	0	0	0	183,140	16	31	31	31
Menasha Corp	A0023	0024	294	Allegan	0.17	511,728	461,675	523,686	514,186	333,643	518,936	44	88	88	88
Menasha Corp	A0023	0025	294	Allegan	0.17	530,507	490,743	534,494	506,831	330,777	532,501	45	91	90	90
MSU	K3249	0053	300	Ingham	0.17	637,673	621,598	599,293	407,107	836,889	737,281	63	126	125	125
MSU	K3249	0054	300	Ingham	0.17	503,492	543,773	532,129	555,702	634,413	595,058	51	101	101	101
MSU	K3249	0055	452	Ingham	0.17	540,050	789,106	699,677	784,297	935,858	862,482	73	147	147	147
MSU	K3249	0056	433	Ingham	0.17	755,606	649,942	1,059,065	713,930	576,236	907,335	77	154	154	154
U of M	M0675	003	315	Washtenaw	0.17	233,845	152,103	141,133	338,819	509,756	424,288	36	72	72	72
U of M	M0675	004	315	Washtenaw	0.17	239,971	168,956	469,248	201,498	516,962	493,105	42	84	84	84
U of M	M0675	006	358	Washtenaw	**0.10**	94,187	508,152	350,087	657,491	130,943	582,822	29	58	58	58
												654	**1,309**	**1,309**	**1,309**

Annual Hardship Request

Company	Plant Name	Boiler ID	MI Original allocations (tons)	Hard Ship Request (tons)	2009 Adjusted Hardships Allowed	2010 Adjusted Hardships Allowed	2011 Adjusted Hardships Allowed	Ave Heat Input MMBTu	Predicted Nox Emission Rate	Calc Needed Allocations (tons)	Current CAIR Allocations (tons)	Prelim Hardships Calc (tons)	Adjusted Hardships Allowed (tons)	Corrected Hardship Values rounding
Hardship Budget:	**1,200**		**ACTUALS w/rounding corrections**					**MDEQ Calculations**						
Detroit PLD	Mistersky	5	103	192	91	91	91	3,563,411	0.168	299	103	196	91	91
Detroit PLD	Mistersky	6	79	170	80	80	80	2,716,602	0.185	251	79	172	80	80
Detroit PLD	Mistersky	7	117	194	92	92	92	4,039,069	0.156	315	117	198	92	92
Detroit PLD	Mistersky	GT-1	5	26	12	12	12	107,856	0.580	31	5	26	12	12
Grand Haven BLP	Sims	3	324	259	119	119	119	4,470,734	0.260	581	324	257	119	119
Holland BPW	De Young	5	167	278	130	130	130	2,307,180	0.388	448	167	281	130	130
Lansing BWL	Eckert Station	1	196	65	32	32	32	2,702,758	0.197	266	196	70	32	32
Lansing BWL	Eckert Station	2	196	120	61	61	61	2,703,802	0.243	329	196	133	61	61
Lansing BWL	Eckert Station	3	216	42	21	21	21	2,980,297	0.175	261	216	45	21	21
Lansing BWL	Eckert Station	4	399	155	74	74	74	5,498,473	0.203	558	399	159	74	74
Lansing BWL	Eckert Station	5	377	157	78	78	78	5,195,875	0.210	546	377	169	78	78
Lansing BWL	Eckert Station	6	375	143	70	70	70	5,165,255	0.204	527	375	152	70	70
Lansing BWL	Erickson	1	792	251	138	138	138	10,912,871	0.200	1,091	792	299	138	138
Marquette. City of	Shiras	3	271	22	15	15	15	3,845,310	0.158	304	271	33	15	15
MSCPA	Enidcott Gen St	1	427	141	47	47	47	5,884,551	0.180	530	427	103	47	47
Wyandotte DMS	Wyandotte	7	193	294	133	133	133	2,657,771	0.362	481	193	288	133	133
Wyandotte DMS	Wyandotte	8	126	29	7	7	7	1,736,679	0.162	141	126	15	7	7
	TOTALS			**2,538**	**1,200**	**1,200**	**1,200**					**2,595**	**1,200**	**1,200**

Ozone Hardship Request

Hardship Budget: 650			**ACTUALS w/rounding corrections**				**MDEQ Calculations**						
Company	Plant Name	Boiler ID	MI Original allocations (tons)	Hard Ship Request (tons)	2010 Adjusted Hardships Rounded	2011 Adjusted Hardships Rounded	Ave Heat Input MMBTu	Predicted Nox Emission Rate	Calc Needed Allocations (tons)	Current CAIR Allocations (tons)	Prelim Hardships Calc (tons)	Adjusted Hardships Allowed (tons)	Corrected Hardship Values rounding
Detroit PLD	Mistersky	5	48	88	48	48	1,629,140	0.168	137	48	89	46	46
Detroit PLD	Mistersky	6	38	80	43	43	1,277,045	0.185	118	38	80	42	42
Detroit PLD	Mistersky	7	51	83	45	45	1,726,396	0.156	135	51	84	44	44
Detroit PLD	Mistersky	GT-1	3	16	9	9	64,829	0.580	19	3	16	8	8
Grand Haven BLP	Sims	3	149	70	39	39	2,018,823	0.260	262	149	113	59	59
Holland BPW	De Young	5	70	113	61	61	943,140	0.388	183	70	113	59	59
Lansing BWL	Eckert Station	1	83	27	16	16	1,139,338	0.197	112	83	29	15	15
Lansing BWL	Eckert Station	2	85	54	29	29	1,148,529	0.243	140	85	55	28	28
Lansing BWL	Eckert Station	3	95	16	9	9	1,283,742	0.175	112	95	17	9	9
Lansing BWL	Eckert Station	4	177	63	35	35	2,376,216	0.203	241	177	64	34	34
Lansing BWL	Eckert Station	5	155	63	35	35	2,089,851	0.210	219	155	64	34	34
Lansing BWL	Eckert Station	6	167	61	34	34	2,261,995	0.204	231	167	64	33	33
Lansing BWL	Erickson	1	367	124	69	69	4,949,905	0.200	495	367	128	67	67
Marquette. City of	Shiras	3	112	13	7	7	1,556,516	0.161	125	112	13	7	7
MSCPA	Enidcott Gen St	1	199	61	98	98	2,686,895	0.180	242	61	181	94	94
Michigan State University	Simon	0053	126	70	0	0	737,281	0.250	92	126	0	0	0
Michigan State University	Simon	0054	101	59	0	0	595,058	0.260	77	101	0	0	0
Michigan State University	Simon	0055	147	112	0	0	862,482	0.270	116	147	0	0	0
Michigan State University	Simon	0056	154	0	0	0	907,335	0.140	64	154	0	0	0
Wyandotte DMS	Wyandotte	7	89	127	69	69	1,201,444	0.362	217	89	128	67	67
Wyandotte DMS	Wyandotte	8	62	6	4	4	840,382	0.162	68	62	6	3	4
	Totals			**1,039**	**650**	**650**					**1,245**	**650**	**650**

Note: MSU's request for hardships is denied.

APPENDIX B

Proposed Rules Submitted to Public Hearing

2005-037EQ

February 9, 2007

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
AIR POLLUTION CONTROL

These rules become effective immediately upon filing with the Secretary of State unless adopted under sections 33, 44, or 45a(6) of 1969 PA 306. Rules adopted under these sections become effective 7 days after filing with the Secretary of State.

(By authority conferred on the director of the department of environmental quality by sections 5503 and 5512 of 1994 PA 451, MCL 324.5503 and 324.5512, and Executive Reorganization Order No. 1995-18, MCL 324.99903)

R 336.1803 is amended and R 336.1802a, R 336.1821, R 336.1822, R 336.1823, R 336.1824, R 336.1825, R 336.1826, R 336.1830, R 336.1831, R 336.1832, R 336.1833 and R 336.1834 are added to the Michigan Administrative Code, as follows:

PART 8. EMISSION LIMITATIONS AND PROHIBITIONS—
OXIDES OF NITROGEN

R 336.1802a Adoption by reference.

Rule 802a. The following documents are adopted by reference in these rules. Copies are available for inspection and purchase at the Air Quality Division, Department of Environmental Quality, 525 West Allegan Street, P.O. Box 30260, Lansing, Michigan 48909-7760, at the cost at the time of adoption of these rules (AQD price). Copies may be obtained from the Superintendent of Documents, Government Printing Office, P.O. Box 371954, Pittsburgh, Pennsylvania, 15250 7954, at the cost at the time of adoption of these rules (GPO price), or on the United States government printing office internet web site at http://www.gpoaccess.gov:

(a) Title 40 C.F.R., §72.2 definitions under the "Acid Rain Program General Provisions" (2006), AQD price $72.00; GPO price $62.00.

(b) Title 40 C.F.R. §72.8, "Retired Units Exemption" (2006), AQD price $72.00; GPO price $62.00

(c) Title 40 C.F.R., part 75, "Continuous Emission Monitoring" (2006), AQD price $72.00; GPO price $62.00.

(d) Title 40 C.F.R., §97.2, 97.102, 97.103, 97.302 and 97.303, definitions under the "Federal Oxides of Nitrogen (NOx) Budget Trading Program and CAIR NOx and Sulfur Dioxide (SO_2) Trading Programs" (2006), AQD price $70.00; GPO price $60.00.

(e) Title 40 C.F.R., part 97; §§97.180 to 97.188 and §§97.380 to 97.388, opt-in provisions under the "Federal Oxides of Nitrogen (NOx) Budget Trading Program and CAIR NOx and Sulfur Dioxide (SO_2) Trading Programs" (2006), AQD price $70.00; GPO price $60.00.

R 336.1803 Definitions~~ for oxides of nitrogen budget trading program~~.

Rule 803. (1) The provisions of 40 C.F.R. §96.2 are adopted by reference in this rule. The definitions **for the oxides of nitrogen budget trading program** in 40 C.F.R. §96.2 are applicable to R 336.1802 to R 336.1816. In addition, all of the following definitions apply as indicated, including a modification to the “NOx budget trading program” definition:

(a) “Electric-generating unit (EGU)” means the following:

(i) For units that commenced operation before January 1, 1997, a unit serving a generator during 1995 or 1996 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale.

(ii) For units that commenced operation on or after January 1, 1997, and before January 1, 1999, a unit serving a generator during 1997 or 1998 that had a nameplate capacity of more than 25 megawatts and produced electricity for sale.

(iii) For units that commence operation on or after January 1, 1999, a unit serving a generator at any time that has a nameplate capacity of more than 25 megawatts and produces electricity for sale.

(b) “Large affected unit” means the following:

(i) For units that commenced operation before January 1, 1997, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1995 or 1996 a generator producing electricity for sale.

(ii) For units that commenced operation on or after January 1, 1997, and before January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1997 or 1998 a generator producing electricity for sale.

(iii) For units that commence operation on or after January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and to which either of the following provisions applies:

(A) The unit at no time serves a generator producing electricity for sale.

(B) The unit at any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of 25 megawatts or less and has the potential to use not more than 50% of the potential electrical output capacity of the unit.

(c) “Michigan fine grid zone” means the geographical area that includes all of the following counties:

(i) Allegan.

(ii) Barry.

(iii) Bay.

(iv) Berrien.

(v) Branch.

(vi) Calhoun.

(vii) Cass.

(viii) Clinton.

(ix) Eaton.

(x) Genesee.

(xi) Gratiot.

(xii) Hillsdale.
(xiii) Ingham.
(xiv) Ionia.
(xv) Isabella.
(xvi) Jackson.
(xvii) Kalamazoo.
(xviii) Kent.
(xix) Lapeer.
(xx) Lenawee.
(xxi) Livingston.
(xxii) Macomb.
(xxiii) Mecosta.
(xxiv) Midland.
(xxv) Monroe.
(xxvi) Montcalm.
(xxvii) Muskegon.
(xxviii) Newaygo.
(xxix) Oakland.
(xxx) Oceana.
(xxxi) Ottawa.
(xxxii) Saginaw.
(xxxiii) Saint Clair.
(xxxiv) Saint Joseph.
(xxxv) Sanilac.
(xxxvi) Shiawassee.
(xxxvii) Tuscola.
(xxxviii) Vanburen.
(xxxix) Washtenaw.
(xxxx) Wayne.

(d) "NOx budget trading program" means a multi-state nitrogen oxides air pollution control and emission reduction program established pursuant to 40 C.F.R. part 96 and part 97. The provisions of 40 C.F.R. part 96 and part 97 are adopted by reference in subrule (2) of this rule.

(e) "Ozone control period" means the period of May 31, 2004, through September 30, 2004, and the period of May 1 to September 30 each subsequent and prior year. The term "ozone control period" replaces the term "control period."

(2) For R 336.1803 to R 336.1816, the provisions of 40 C.F.R. part 96 and part 97 (2006) are adopted by reference, except as modified in R 336.1804, R 336.1805, R 336.1808, R 336.1811, R 336.1813, and R 336.1815. Copies may be inspected at the Lansing office of the air quality division of the department of environmental quality. Copies of the regulations may be obtained from the Department of Environmental Quality, Air Quality Division, 525 West Allegan Street, P.O. Box 30260, Lansing, Michigan 48909-7760, at a cost as of the time of adoption of this rule of $70.00. A copy may also be obtained from the Superintendent of Documents, Government Printing Office, P.O. Box 371954, Pittsburgh, Pennsylvania

15250-7954, at a cost as of the time of adoption of this rule of $60.00; or on the United States government printing office internet web site at www.access.gpo.gov.

(3) Definitions under the clean air interstate rule NOx ozone season and annual trading programs in 40 C.F.R. §97.102 and §97.302 are applicable to R 336.1821 to R 336.1834. In addition, all of the following definitions apply as indicated:

(a) "Biomass" means wood, wood residue, and wood products (for example, trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal litter; vegetative agricultural, and silvicultural materials, such as logging residues (slash), nut and grain hulls, and chaff (for example, almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.

(b) "CAIR" means clean air interstate rule.

(c) "Commence operation" as defined in 40 C.F.R. Part 97, solely for purposes of 40 C.F.R. Part 97, subpart HHHH, for a unit that is not currently a CAIR NO_X Ozone Season unit under R 336.1803(3)(d) means the following:

(i) On the later of November 15, 1990, or the date the unit commences operation and that subsequently becomes such a CAIR NO_X ozone season unit, the unit's date for commencement of operation shall be the date on which the unit becomes a CAIR NO_X ozone season unit under R 336.1803(3)(d).

(ii) For a unit with a date of commencement of operation as defined in this subrule and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(iii) For a unit with a date for commencement of operation as defined in this subrule and that is subsequently replaced by a unit at the same source (for example, repowered), such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in this subrule as appropriate.

(d) "EGU" means electric generating unit.

(e) "Existing EGUs" for allocation purposes under R 336.1821 to R 336.1834, means electric generating units that commenced operations prior to the most recent year of the 5-year period used to calculate the allocations pursuant to these rules.

(f) "Fossil fuel-fired," for the purposes of determining applicability for units that are considered Michigan non-EGUs, means as defined in 40 C.F.R. §97.2.

(g) "Fuel types," for the allocation of allowances under Michigan's programs only, means solid, liquid and gaseous fuel. The following definitions apply to fuel:

(i) "Solid fuel" includes, but is not limited to coal, biomass, tire-derived fuels and pet coke.

(ii) "Liquid fuel" includes, but is not limited to petroleum-based oils, glycerol, vegetable-based and animal waste-based liquids.

(iii) "Gaseous fuel" includes, but is not limited to natural gas, propane, coal gas, blast furnace gas, and methane derived from animal wastes.

(h) "Michigan EGUs" means any stationary fossil fuel-fired boiler or stationary fossil fuel-fired combustion turbine serving, at any time since the later of November 15, 1990, or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 megawatts producing electricity for sale and geographically located in Michigan.

(i) "Michigan fine grid zone" means the geographical area that includes all of the following counties:

(i) Allegan.

(ii) Barry.

(iii) Bay.

(iv) Berrien.

(v) Branch.

(vi) Calhoun.

(vii) Cass.

(viii) Clinton.

(ix) Eaton.

(x) Genesee.

(xi) Gratiot.

(xii) Hillsdale.

(xiii) Ingham.

(xiv) Ionia.

(xv) Isabella.

(xvi) Jackson.

(xvii) Kalamazoo.

(xviii) Kent.

(xix) Lapeer.

(xx) Lenawee.

(xxi) Livingston.

(xxii) Macomb.

(xxiii) Mecosta.

(xxiv) Midland.

(xxv) Monroe.

(xxvi) Montcalm.

(xxvii) Muskegon.

(xxviii) Newaygo.

(xxix) Oakland.

(xxx) Oceana.

(xxxi) Ottawa.

(xxxii) Saginaw.

(xxxiii) Saint Clair.

(xxxiv) Saint Joseph.

(xxxv) Sanilac.

(xxxvi) Shiawassee.

(xxxvii) Tuscola.

(xxxviii) Vanburen.

(xxxix) Washtenaw.

(xxxx) Wayne.

(j) “Michigan non-EGUs” means the following:

(i) For units that commenced operation before January 1, 1997, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1995 or 1996 a generator producing electricity for sale.

(ii) For units that commenced operation on or after January 1, 1997, and before January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and that did not serve during 1997 or 1998 a generator producing electricity for sale.

(iii) For units that commence operation on or after January 1, 1999, a unit that has a maximum design heat input of more than 250,000,000 Btu's per hour and to which either of the following provisions applies:

(A) The unit at no time serves a generator producing electricity for sale.

(B) The unit at any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of 25 megawatts or less and has the potential to use not more than 50% of the potential electrical output capacity of the unit.

(k) “New EGUs,” for allocation purposes under R 336.1821 to R 336.1834, means electric generating units that are commencing operation or projected to commence operation on or after January 1 of the most recent year of the 5-year period used to calculate the allocations pursuant to these rules.

(l) “Newly-affected EGUs,” for allocation purposes under R 336.1821 to R 336.1834, means existing EGUs located outside the Michigan fine grid zone or existing EGUs located within the Michigan fine grid zone which were exempt from the federal NOx budget program. This definition is applicable for the 2009 CAIR NOx ozone season program only and after that time the newly affected EGUs are considered existing EGUs.

(m) “Ozone Season” means May 1 to September 30 of each calendar year.

(n) “Renewable energy source,” for allocation purposes under R 336.1821 to R 336.1834, means a source that generates electricity by solar, wind, geothermal, or hydroelectric processes, excluding nuclear, that has commenced operation or is projected to commence operation on or after January 1 of the most recent year of the 5-year period used to calculate the allocations pursuant to these rules, which meets all of the following:

(i) Serves a generator at 25 megawatts or greater of electrical output.

(ii) Is not subject to R 336.1801(4)(a) or covered by any other definitions in this rule.

(iii) Captures energy from on-going natural processes.

(iv) Is considered a non-emitting, having zero emissions, source.

(o) “Renewable energy projects,” for allocation purposes under R 336.1821 to R 336.1834, means renewable energy sources located within the same geographic area that when added together equal a generator greater than 25 megawatts of electrical output.

R 336.1821 CAIR NOx ozone season and annual trading programs; applicability determinations.

Rule 821. (1) This rule establishes Michigan's CAIR ozone season and annual emission budgets and trading programs for all of the following units:

(a) Annual CAIR NOx units as defined pursuant to 40 C.F.R. part 97.

(b) Ozone season CAIR NOx units as defined pursuant to 40 C.F.R part 97 and all units required to be in the state's NOx SIP call trading program that are not already included under 40 C.F.R. §96.304 and are defined in R 336.1803(3)(h) and (j).

(c) For purposes of allocating allowances under R 336.1821 to R 336.1834, the following units which are not addressed in subparagraphs (a) and (b) of this subrule are CAIR NOx units:

(i) Renewable energy sources

(ii) Renewable source projects

(2) A Michigan source subject to the requirements pursuant to 40 C.F.R. §97.104, CAIR NOx Annual, or 40 C.F.R. §97.304, CAIR NOx ozone season, shall apply for and receive an annual or ozone season CAIR NOx permit. This permit shall be administered under R 336.1214 and shall be incorporated into the source's renewable operating permit as an attachment. A federally enforceable NOx budget permit issued under the federal NOx budget program pursuant to R 336.1808 shall remain in effect until the CAIR NOx ozone season permit has been approved by the department.

(3) After January 1, 2008, any Michigan EGU that does not utilize fossil fuels of any kind for the production of electricity is determined to be exempt from R 336.1802a to R 336.1834.

(4) The fuel type adjusted allocations for each EGU shall be determined by multiplying the appropriate coefficient as follows:

(a) For a solid fuel-fired EGU or cogeneration unit, the allocation calculations shall be adjusted by multiplying the allocation values by 100%.

(b) For a liquid fuel-fired EGU or cogeneration unit, the allocation calculations shall be adjusted by multiplying the allocation values by 60%.

(c) For a gaseous fuel-fired EGU or cogeneration unit, the allocation calculations shall be adjusted by multiplying the allocation values by 40%.

(d) For a multi-fueled EGU, the allocation adjustment calculation shall be a weighted average based on the percentage heat input from each type of fuel burned in the unit, unless the source can demonstrate that certain types of fuel used in the process provided less than 10% of the annual heat input. If so, then the allocation adjustment is calculated based on only those fuel types which contributed 10% or more of the annual heat input.

(5) The owner or operator of any CAIR NOx ozone season or annual unit shall submit all of the following data within 30 days upon request by the department:

(a) A unit's ozone season and annual heat input values or megawatt energy produced, which shall be the same data reported in accordance with 40 C.F.R.

part 75 to the extent the unit is subject to 40 C.F.R. part 75 for the period involved.

(b) A unit's total tons of oxides of nitrogen emissions during specified calendar years as determined under 40 C.F.R. part 75, adopted by reference in R 336.1802.

(6) Effective January 1, 2009, the provisions of R 336.1802, R 336.1803(1) and R 336.1803(2), R 336.1804, R 336.1805, R 336.1806, R 336.1807, R 336.1808, R 336.1809, R 336.1810, R 336.1811, R 336.1812, R 336.1813, R 336.1814, R 336.1815, and R 336.1816 shall not apply to the control period beginning in 2009 or any control period thereafter.

(7) Pursuant to the provisions in 40 C.F.R. §§96.30 and 96.31 and for the 2009 control period only, if the U.S. environmental protection agency determines that there were excess emissions during the 2008 control period, deductions for excessive emission penalties shall be taken from the 2009 allowances.

(8) Pursuant to any NOx SIP unused set-aside allowances through 2008 that are accumulated within the state account, the department shall allocate these allowances according to R 336.1823.

R 336.1822 CAIR NOx ozone season trading program; allowance allocations.

Rule 822. (1) The CAIR NOx ozone season trading program budget allocated by the department under subrule (3) of this rule for the CAIR NOx ozone season control periods to the EGUs, non-EGUs, and renewable units shall equal the total number of tons of oxides of nitrogen emissions as indicated in the following manner:

(a) The total CAIR NOx ozone season budget for the ozone season time period of 2010 to 2014 is 31,180 tons. These allocations shall be distributed as follows:

(i) The CAIR NOx ozone season budget available to existing and newly-affected EGUs. The following applies:

(A) For 2010 and 2011 ozone season control periods equals 28,321 tons.

(B) For 2012 to 2014 ozone season control periods equals 28,021 tons.

(ii) The CAIR NOx ozone season budget available to existing non-EGUs for the 2010 to 2014 ozone season control periods is 1,309 tons.

(iii) The CAIR NOx ozone season budget available to new non-EGUs and EGUs. The following applies:

(A) For 2010 and 2011 ozone season control periods is 700 tons.

(B) For 2012 to 2014 ozone season control periods is 1,000 tons.

(iv) The CAIR NOx ozone season budget available to renewable energy sources and projects in the 2010 to 2014 ozone season control periods is 200 tons.

(v) The CAIR NOx ozone season budget available to all existing EGUs and non-EGUs that have submitted an acceptable demonstration of a hardship to the department, in the 2010 to 2014 ozone season control periods is 650 tons.

(b) The total CAIR NOx ozone season budget for the ozone season time period of 2015 and thereafter is 26,351 tons. These allocations shall be distributed as follows:

(i) The CAIR NOx ozone season budget available to existing EGUs in the 2015 and thereafter ozone season control periods is 22,792 tons.

(ii) The CAIR NOx ozone season budget available to existing CAIR NOx ozone season budget non-EGUs for the 2015 and thereafter ozone season control periods is 1,309 tons.

(iii) The CAIR NOx ozone season budget available to new non-EGUs and EGUs in the 2015 and thereafter ozone season control periods is 1,400 tons.

(iv) The CAIR NOx ozone season budget available to renewable energy sources and projects in the 2015 and thereafter ozone season control periods is 200 tons.

(v) The CAIR NOx ozone season budget available to all existing EGUs and non-EGUs that have submitted an acceptable demonstration of hardship to the department, in the 2015 and thereafter ozone season control periods is 650 tons.

(2) CAIR NOx allowances for the 2009 ozone season control period shall be the same allowances as were allocated under the NOx budget trading program. For newly-affected EGUs which were not subject to the federal NOx budget program, their units are eligible for allowances from the CAIR NOx ozone season new source set-aside pool for the 2009 ozone season, pursuant to R 336.1823.

(3) The department shall allocate CAIR NOx ozone season allowances to existing EGUs and non-EGU ozone season units for calendar years 2010 and thereafter according to the following schedule:

(a) A 3-year allocation that is 3 years in advance of the ozone season control period in which the allowances are to be used. The 3-year allocation shall be as follows:

(i) By 60 days after the effective date of this rule or April 30, 2007, whichever is earlier, the department shall submit to the U.S. environmental protection agency the CAIR NOx ozone season allowance allocations, under this subrule, for the ozone season control periods in 2010 and 2011.

(ii) By October 31, 2008, the department shall submit to the U.S. environmental protection agency the CAIR NOx ozone season allowance allocations, under this subrule, for the ozone season control periods in 2012, 2013, and 2014.

(iii) By October 31, 2011, and thereafter each October 31 of the year that is 3 years after the last year of allocation submittal, the department shall submit to the U.S. environmental protection agency the CAIR NOx ozone season allowance allocations as indicated under this subrule.

(4) For the CAIR NOx ozone season control periods under subrule (3) of this rule, the department shall allocate allowances to existing EGU and non-EGU ozone season units that commenced operation before January 1 of the most recent year of the 5-year period used to calculate heat input as follows:

(a) The department shall allocate allowances to each existing EGU ozone season unit as follows:

(i) During calendar years 2010 to 2014 as follows:

(A) Units with an allowable emission rate equal to or greater than the CAIR target budget rate of 0.15 pounds per million Btu shall receive allowances in an amount equaling 0.15 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(B) Units with an allowable emission rate less than the CAIR target budget rate of 0.15 pounds per million Btu shall receive allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

$$Allocation = \left[\frac{\left\{ \frac{(CTER \ x \, FAF) + AER}{2} \right\} x \ HI}{2000 \, lb/ton} \right]$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
CTER =	**The CAIR target emission rate for 2009 to 2014.**
FAF =	**Fuel adjustment factor as defined in R 336.1821.**
AER =	**The unit's allowable emission rate.**
HI =	**Average of the unit's 2 highest heat inputs for the appropriate 5 control periods.**

(ii) During calendar years 2015 and thereafter as follows:

(A) Units with an allowable emission rate equal to or greater than the CAIR target budget rate of 0.125 pounds per million Btu shall receive allowances in an amount equaling 0.125 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(B) Units with an allowable emission rate less than the CAIR target budget rate of 0.125 pounds per million Btu shall receive allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

$$Allocation = \left[\frac{\left\{ \frac{(CTER\ x\ FAF) + AER}{2} \right\} x\ HI}{2000 lb/ton} \right]$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
CTER =	**The CAIR target emission rate for 2015 and thereafter.**
FAF =	**Fuel adjustment factor as defined in R 336.1821.**
AER =	**The unit's allowable emission rate.**
HI =	**Average of the unit's 2 highest heat inputs for the appropriate 5 control periods.**

(b) The department shall allocate allowances to each existing non-EGU ozone season unit for calendar years 2010 to 2015 and thereafter in an amount equaling 0.17 pounds per million Btu or the allowable emission rate, whichever is more stringent, multiplied by the heat input as determined under subrule (6) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(5) If the initial total number of CAIR NOx ozone season budget allowances allocated to all existing EGU and non-EGU ozone season units for the years under subrule (4) of this rule does not equal the tons as specified in subrule (1) of this rule, then the department shall adjust up or down the total number of CAIR NOx ozone season budget allowances allocated to all CAIR NOx ozone season units so that the total number of CAIR NOx ozone season budget allowances allocated equals the values in subrule (1) of this rule. The adjustment shall be made by multiplying each unit's allocation by a correction factor determined by dividing the total number of the budget tons being allocated by the sum of all units' allocations.

(6) The heat input, in million Btu's, used for calculating oxides of nitrogen allowance allocations for each subject unit under this rule shall be the unit's average of the 2 highest heat inputs for the ozone season control period in the 5 years immediately preceding the year in which the department is required to submit the oxide of nitrogen allocations. If the unit operated less than 2 full ozone seasons of the 5-year time period, then the unit's single highest heat input shall be used.

R 336.1823 New EGUs, new non-EGUs, and newly-affected EGUs under CAIR NOx ozone season trading program; allowance allocations.

Rule 823. (1) The department shall establish a set-aside pool for each CAIR NOx ozone season control allocation year for new EGUs and non-EGUs. This set-aside pool shall be allocated on a yearly basis as follows:

(a) For 2009, a total of 1,385 tons of CAIR NOx ozone season allowances, which have been carried over from the federal NOx budget program, for any new and newly-affected EGUs or new non-EGUs.

(b) For years 2010 and 2011, a total of 700 tons of CAIR NOx ozone season allowances for any new EGUs or new non-EGUs.

(c) For years 2012 to 2014 ozone season control periods, a total of 1,000 tons of CAIR NOx ozone season allowances for any new EGUs or new non-EGUs.

(d) For years 2015 and thereafter, a total of 1,400 tons of CAIR NOx ozone season allowances for any new EGUs or new non-EGUs.

(2) The CAIR authorized account representative of a newly-affected CAIR NOx ozone season EGU under this rule may submit to the department a request, in a format specified by the department, to receive CAIR NOx ozone season allowances for the 2009 CAIR NOx ozone season control period. All of the following apply:

(a) The oxides of nitrogen allowance allocation request shall be submitted before March 1 of the 2009 ozone season control period.

(b) The CAIR authorized account representative of any newly-affected EGU may request 2009 CAIR NOx ozone season allowances, based on an amount equaling 0.15 pounds per million Btu multiplied by the unit's ozone season heat input, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(c) The heat input, in million Btu's, used for calculating oxides of nitrogen allowance allocations for each subject unit under this rule shall be the unit's average of the 2 highest heat inputs for the ozone season control period in the 5 years immediately preceding the year in which the department is required to submit the oxide of nitrogen allocations. If the unit operated less than 2 full ozone seasons of the 5-year time period, then the unit's single highest heat input shall be used.

(3) The CAIR authorized account representative of a new CAIR NOx ozone season non-EGU under this rule may submit to the department a request, in a format specified by the department, to receive CAIR NOx ozone season allowances for the CAIR NOx ozone season control period. Both of the following apply:

(a) The CAIR NOx ozone season allowance allocation request shall be submitted before March 1 of the year of the first ozone control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the oxides of nitrogen unit, if required, and each following year by March 1.

(b) The CAIR authorized account representative of any new non-EGU may request CAIR NOx ozone season allowances, based on an amount equaling 0.17 pounds per million Btu or the allowable emission rate, whichever is more stringent, multiplied by the maximum design heat input or the permit allowable heat input, whichever is more stringent, in million Btu's per hour, divided by 2,000 pounds per ton and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(4) The CAIR authorized account representative of a new EGU CAIR NOx ozone season unit under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx ozone season allowances, starting with the ozone season control period during which the CAIR NOx ozone season unit commenced or is projected to

commence operation and ending with the control period preceding the control period for which it shall receive an allocation under R 336.1822. All of the following apply:

(a) The CAIR NOx ozone season allowance allocation request shall be submitted before March 1 of the year of the first ozone control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the oxides of nitrogen unit, if required, and each following year by March 1.

(b) The allocation methodology used for the first ozone season for which each new EGU requests allowances shall be calculated using the following formula*:*

$$Allocation = \frac{1.0 lb\ NOx}{MWh}\ X\ \frac{Size\ of\ unit\ in\ MW\ x\ hours\ of\ operation}{2000\ lb / ton}\ X\ 70\%$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
1.0 lb NOx/MWh =	**The factor for allocating NOx allowances based on electric generation.**
Size of the unit =	**The maximum design capacity of the EGU in megawatts.**
Hours of Operation =	**Predicted hours of operation per control period.**
MWh =	**Megawatt hours.**

(c) The allocation methodology used for each consecutive ozone season for which each new EGU requests allowances shall be calculated using the following formula*:*

$$Allocation = \frac{1.0 lb\ NOx}{MWh}\ X\ \frac{Actual\ Megawatt\ hours}{2000\ lb / ton}$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
1.0 lb NOx/MWh =	**The factor for allocating NOx allowances based on electric generation.**
Actual megawatt hours =	**The actual megawatt hours of electricity generated during the control period immediately preceding the request.**
MWh =	**Megawatt hours.**

(d) When the new EGU has been placed in the existing pool, the calculation methods under R 336.1822 apply.

(5) The department shall review and allocate oxides of nitrogen allowances pursuant to each allocation request on a pro rata basis as follows:

(a) Upon receipt of the CAIR NOx unit's allowance allocation request, the department shall determine whether allowances are available and shall make necessary adjustments to the request to ensure that for the CAIR NOx ozone

season control period, the number of allowances specified are consistent with the requirements of subrule (1) of this rule.

(b) If the allocation set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount greater than or equal to the number requested, as adjusted under subdivision (a) of this subrule, then the department shall allocate the amount of the CAIR NOx ozone season allowances requested.

(c) If the allocation set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, as adjusted under subdivision (a) of this subrule, then the department shall proportionately reduce the number of CAIR NOx ozone season allowances allocated to each CAIR NOx ozone season unit so that the total number of CAIR NOx ozone season allowances allocated are equal to the amounts referenced in subrule (1)(a), (b) or (c) of this rule.

(6) CAIR NOx ozone season allowances not allocated or requested that remain in the new source set-aside pool for any allocation year shall be re-allocated to the existing EGU and non-EGU source pools, using the allocation methodologies as outlined in R 336.1822.

(7) Not later than July 31 of the year for which the allowances are allocated, the department shall submit to the U.S. environmental protection agency the CAIR NOx ozone season allowance allocations, as determined under this rule.

R 336.1824 CAIR NOx ozone season trading program; hardship set-aside.

Rule 824. (1) After the provisions of R 336.1822 have been followed, the authorized account representative may pursue a request for hardship allowances. These requests must be submitted not later than 30 days prior to the deadline for department submittals to the U.S. environmental protection agency as described in R 336.1822.

(2) For existing EGUs and non-EGUs subject to the CAIR NOx ozone season budget, the department shall allocate CAIR NOx hardship allowances under the following procedures:

(a) The department shall establish a hardship allocation set-aside pool for each CAIR NOx ozone season allocation year. This hardship set-aside pool shall be allocated on an ozone season basis and contains a total of 650 tons per allocation year of CAIR NOx ozone season allowances, for any qualifying EGUs or non-EGUs.

(b) Hardship allowances may be allocated to an EGU or non-EGU, if the requesting authorized account representative demonstrates both of the following:

(i) The owner or operator of the EGU or a non-EGU has less than 250 employees within its company or its electric generating division or department.

(ii) The controls required for the EGU or non-EGU under this part result in excessive or prohibitive costs for compliance, pursuant to the procedures in subrule (3) of this rule.

(c) The CAIR authorized account representative of a CAIR NOx ozone season unit under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx ozone season hardship allowances. The authorized account representative shall submit the request for the amount of estimated hardship allowances they need, using historical ozone season heat input utilization levels multiplied by historical oxides of nitrogen emission rates as follows:

(i) Historical heat input utilization levels shall be based on the unit's average of the 2 highest heat input utilization levels for the ozone season in the 5 years immediately preceding the year in which the department is required to submit the oxides of nitrogen allocations to the U.S. environmental protection agency. If the unit operated less than 2 full ozone seasons during the 5-year time period, then the unit's single highest heat input level shall be used.

(ii) Historic oxides of nitrogen rates shall be based on the oxides of nitrogen rate reported by the authorized account representative in its 40 C.F.R. part 75 reports to the U.S. environmental protection agency in the calendar year immediately preceding the year in which the department is required to submit the oxides of nitrogen allocation.

(iii) Units receiving hardship allowances shall receive a 3-year allocation that is 3 years in advance of the ozone season control period in which the hardship allowances are to be used. The 3-year allocation shall be the same as provided in R 336.1822(3).

(d) The department shall allocate the allowances from the hardship set-aside pool based on the requests received as follows:

(i) If the allocation hardship set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount of oxides of nitrogen allowances greater than or equal to the number requested, then the department shall allocate the amount of the CAIR NOx ozone season allowances requested.

(ii) If the allocation hardship set-aside pool for the CAIR NOx ozone season control period for which CAIR NOx ozone season allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, then the department shall proportionately reduce the number of CAIR NOx ozone season allowances allocated to each CAIR NOx ozone season unit so that the total number of CAIR NOx ozone season allowances allocated are equal to the amounts in R 336.1822(1)(a)(v) or (b)(v).

(3) The department shall allocate CAIR NOx ozone season hardship allowances to existing CAIR NOx ozone season units which have submitted an engineering analysis as described in the following procedures:

(a) The authorized account representative shall demonstrate to the department that the control level required pursuant to this rule results in excessive or prohibitive cost for compliance. The demonstration shall include all of the following:

(i) An engineering study analyzing all control options that are technically available for the unit, including control options that would achieve a level of

control meeting, at a minimum, a 0.15 pound per million Btu emission rate. Sources that previously submitted an engineering analysis and received hardship allowances pursuant to R 336.1810(4)(f) for the oxides of nitrogen budget program may submit written updates to their previous plan.

(ii) The annualized cost associated with each control option. An annualized cost of more than $2,400 per ton of oxide of nitrogen reduced shall generally be considered to be an excessive cost for compliance with this rule.

(iii) Other considerations that contribute to prohibitive cost of compliance.

(b) For a source to remain eligible for hardship allowances under this rule after the initial 3-year allocation period, ending on September 30, 2011, the state may require a revised engineering analysis and demonstration as referenced in subrule (3)(a) of this rule, at a minimum of once every 3 years.

R 336.1825 CAIR NOx ozone season trading program; renewable set-aside.

Rule 825. (1) The department shall establish a renewable allocation set-aside pool for each CAIR NOx ozone season control period for applicable units. This renewable set-aside pool shall be allocated on a yearly basis and contain a total of 200 tons of oxides of nitrogen allowances per allocation year.

(2) An authorized account representative of a renewable energy source or renewable energy project, as defined under R 336.1803, may request a CAIR NOx ozone season allowance allocation under this rule.

(3) Once an authorized account representative of a renewable energy source or renewable energy project has requested allowances from the CAIR NOx ozone season budget, the department shall allocate CAIR NOx ozone season renewable allowances under the following procedures:

(a) The oxides of nitrogen allowance allocation request shall be submitted before March 1 of the year of the first ozone control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the unit, if required, and each following year by March 1.

(b) The allocation methodology used for the first ozone season for which each renewable energy source or renewable energy project requests allowances shall be calculated using the following formula*:*

$$Allocation = \frac{1.0lb\ NOx}{MWh}\ X\ \frac{Size\ of\ \ unit\ in\ MW\ \ x\ hours\ of\ \ operation}{2000\ lb\ /\ ton}\ X\ 70\%$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
1.0 lb NOx/MWh =	**The factor for allocating NOx allowances based on electric generation.**
Size of the unit =	**The maximum design capacity of the renewable energy source or renewable energy project in megawatts.**
Hours of Operation =	**Predicted hours of operation per control period.**
MWh =	**Megawatt hours.**

(c) The allocation methodology used for the each consecutive ozone season for which the renewable energy source or renewable energy project requests allowances shall be calculated using the following formula:

$$Allocation = \frac{1.0lb\ NOx}{MWh}\ X\ \frac{Actual\ Megawatt\ hours}{2000\ lb\ /\ ton}$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
1.0 lb NOx/MWh =	**The factor for allocating NOx allowances based on electric generation.**
Actual megawatt hours =	**The actual megawatt hours of electricity generated during the control period immediately preceding the request.**
MWh =	**Megawatt hours.**

(4) The renewable energy source or renewable energy project's eligibility to request allowances shall begin not sooner than the calendar year 2005.

(5) The authorized account representative of a renewable energy source or renewable energy project may only request allowances for 3 consecutive ozone seasons.

(6) CAIR NOx ozone season allowances not allocated or requested that remain in the renewable allocation set-aside pool for any allocation year shall be re-allocated to the existing EGU and non-EGU source pools, using the allocation methodologies as outlined in Rule 822.

R 336.1826 CAIR NOx ozone season trading program; opt-in provisions.

Rule 826. The opt-in provisions in 40 C.F.R. §§97.380 to 97.388 are adopted by reference in R 336.1802a and are applicable to this rule.

R 336.1830 CAIR NOx annual trading program; allowance allocations.

Rule 830. (1) The CAIR NOx annual trading program budget allocated by the department for the CAIR NOx annual control periods shall equal the total number of tons of oxides of nitrogen emissions as follows and apportioned to the CAIR NOx EGUs, as determined by the procedures in this rule. These allocations shall be distributed in the following manner:

(a) The total CAIR NOx annual budget for the annual control periods of 2009 to 2014 is 65,304 tons. These allocations shall be distributed in the following manner:

(i) The CAIR NOx annual budget available to existing EGUs as follows:

(A) For the 2009 through 2011 annual control periods is 63,104.

(B) For the 2012 through 2014 annual control periods is 62,704.

(ii) The CAIR NOx annual budget available to new EGUs as follows:

(A) For the 2009 through 2011 annual control periods is 1,000 tons.

(B) For the 2012 through 2014 annual control periods is 1,400 tons.

(iii) The CAIR NOx annual budget available to all existing EGUs that have submitted an acceptable demonstration of a hardship to the department, in the 2009 to 2014 annual control periods is 1,200 tons.

(b) The total CAIR NOx annual budget for the annual control periods of 2015 and thereafter is 54,420 tons. These allocations shall be distributed as follows:

(i) The CAIR NOx annual budget available for existing EGUs in the 2015 and thereafter annual control periods is 51,820 tons.

(ii) The CAIR NOx annual budget available for new EGUs in the 2015 and thereafter annual control periods is 1,400 tons.

(iii) The CAIR NOx annual budget available to all existing EGUs that have submitted an acceptable demonstration of a hardship to the department, in the 2015 and thereafter annual control periods is 1,200 tons.

(2) The department shall allocate CAIR NOx annual budget allowances to existing CAIR NOx units. A 3-year allocation is 3 years in advance of the annual control period in which the allowances are to be used. The 3-year allocation shall be as follows:

(a) By 60 days after the effective date of this rule or April 30, 2007, whichever is earlier, the department shall submit to the U.S. environmental protection agency the CAIR NOx annual allowance allocations, under subrule (3) of this rule, for the annual control periods in 2009, 2010, and 2011.

(b) By October 31, 2008, the department shall submit to the U.S. environmental protection agency the CAIR NOx annual allowance allocations, under subrule (3) of this rule, for the annual control periods in 2012, 2013, and 2014.

(c) By October 31, 2011, and thereafter each October 31 of the year that is 3 years after the last year of allocation submittal, the department shall submit to the U.S. environmental protection agency the CAIR NOx annual allowance allocations as indicated under subrule (3) of this rule.

(3) For the CAIR NOx annual control periods under subrules (1)(a) and (b) of this rule, the department shall allocate allowances to existing EGU units that commenced operation before January 1 of the most recent year of the 5-year period used to calculate heat input. The department shall allocate the following allowances to each existing CAIR NOx unit:

(a) During calendar years 2010 to 2014:

(i) Units with an allowable emission rate equal to or greater than the CAIR target budget rate of 0.15 pounds per million Btu shall receive allowances in an amount equaling 0.15 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(ii) Units with an allowable emission rate less than the CAIR target budget rate of 0.15 pounds per million Btu shall receive allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule

(4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

$$Allocation = \left[\frac{\left\{ \frac{(CTER \ X \ FAF) + AER}{2} \right\} X \ HI}{2000 \ lb / ton} \right]$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
CTER =	**The CAIR target emission rate for 2009 through 2014.**
FAF =	**Fuel adjustment factor as defined in R 336.1821.**
AER =	**The unit's allowable emission rate.**
HI =	**Average of the unit's 2 highest heat inputs for the appropriate 5 control periods.**

(b) During calendar years 2015 and thereafter, the following apply:

(i) Units with an allowable emission rate equal to or greater than the CAIR target budget rate of 0.125 pounds per million Btu shall receive allowances in an amount equaling 0.125 pounds per million Btu multiplied by the appropriate fuel adjustment factor and multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

(ii) Units with an allowable emission rate less than the CAIR target budget rate of 0.125 pounds per million Btu shall receive allowances determined by calculating the arithmetic average of the CAIR target emission rate multiplied by the appropriate fuel adjustment factor plus the unit's allowable emission rate, which is then multiplied by the heat input as determined under subrule (4) of this rule, divided by 2,000 pounds per ton, and rounded to the nearest whole oxides of nitrogen allowance, as appropriate.

$$Allocation = \left[\frac{\left\{ \frac{(CTER \ X \ FAF) + AER}{2} \right\} X \ HI}{2000 \ lb / ton} \right]$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
CTER =	**The CAIR target emission rate for 2015 and thereafter.**
FAF =	**Fuel adjustment factor as defined in R 336.1821.**
AER =	**The unit's allowable emission rate.**
HI =	**Average of the unit's 2 highest heat inputs for the appropriate 5 control periods.**

(4) The heat input, in million Btu's, used for calculating oxides of nitrogen allowance allocations for each subject unit under this rule shall be the unit's average of the 2 highest heat inputs for the annual control period in the 5 years immediately preceding the year in which the department is required to

submit the oxide of nitrogen allocations. If the unit operated less than 2 years of the 5-year time period, then the unit's single highest heat input shall be used.

R 336.1831 New EGUs under CAIR NOx annual trading program; allowance allocations.

Rule 831. (1) The department shall establish a set-aside pool for each CAIR NOx annual control allocation year. This set-aside pool shall be allocated on a yearly basis as follows:

(a) For years 2009 to 2011, a total of 1,000 tons of CAIR NOx annual budget allowances available for new EGUs.

(b) For years 2012 and thereafter, a total of 1,400 tons of CAIR NOx annual budget allowances available for new EGUs.

(2) The CAIR authorized account representative of a new EGU CAIR NOx unit under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx annual allowances, starting with the annual control period during which the CAIR NOx unit commenced or is projected to commence operation and ending with the control period preceding the control period for which it shall receive an allocation under R 336.1830.

(a) The oxides of nitrogen allowance allocation request shall be submitted before September 1 of the year of the first annual control period for which the oxides of nitrogen allowance allocation is requested and after the date on which the department issues a permit to install for the oxides of nitrogen unit, if required, and each following year by September 1.

(b) The allocation methodology used for the first annual control period for which each new EGU requests allowances shall be calculated using the following formula*:*

$$Allocation = \frac{1.0lb\ NOx}{MWh}\ X\ \frac{Size\ of\ unit\ in\ MW\ x\ hours\ of\ operation}{2000\ lb / ton}\ X\ 70\%$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
1.0 lb NOx/MWh =	**The factor for allocating NOx allowances based on electric generation.**
Size of the unit =	**The maximum design capacity of the EGU in megawatts.**
Hours of operation =	**Predicted hours of operation per control period.**
MWh =	**Megawatt hours.**

(c) The allocation methodology used for each consecutive annual control period for which each new EGU requests allowances shall be calculated using the following formula*:*

$$Allocation = \frac{1.0lb\ NOx}{MWh}\ X\ \frac{Actual\ Megawatt\ hours}{2000\ lb / ton}$$

Where:

Allocation =	**The unadjusted NOx allowance allocation, in tons.**
1.0 lb NOx/MWh =	**The factor for allocating NOx allowances based on electric generation.**
Actual megawatt hours =	**The actual megawatt hours of electricity generated during the control period immediately preceding the request.**
MWh =	**Megawatt hours.**

(d) Once the new EGU has been placed in the existing pool, the calculation methods under R 336.1830 apply.

(3) The department shall review and allocate oxides of nitrogen allowances pursuant to each allocation request on a pro rata basis as follows:

(a) Upon receipt of the CAIR NOx unit's allowance allocation request, the department shall determine whether allowances are available and shall make necessary adjustments to the request to ensure that for the CAIR NOx annual control period, the numbers of allowances specified are consistent with the requirements of subrule (1) of this rule.

(b) If the allocation set-aside pool for the CAIR NOx annual control period for which CAIR NOx annual budget allowances are requested has an amount greater than or equal to the number requested, as adjusted under subdivision (a) of this subrule, then the department shall allocate the amount of the CAIR NOx annual budget allowances requested.

(c) If the allocation set-aside pool for the CAIR NOx annual control period for which CAIR NOx annual budget allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, as adjusted under subdivision (a) of this subrule, then the department shall proportionately reduce the number of CAIR NOx annual budget allowances allocated to each CAIR NOx unit so that the total number of CAIR NOx annual budget allowances allocated are equal to the amounts referenced in subrule (1)(a) or (b) of this rule.

(4) CAIR NOx annual allowances not allocated or requested that remain in the new source set-aside pool for any allocation year shall be re-allocated to the existing EGU source pool, using the allocation methodologies as outlined in R 336.1830.

R 336.1832 CAIR NOx annual trading program; hardship set-aside.

Rule 832. (1) After the provisions of R 336.1830 have been followed, an owner or operator may pursue a request for hardship allowances. These requests must be submitted not later than 30 days prior to the deadline for department submittals to the U.S. environmental protection agency as described in R 336.1830.

(2) For existing EGUs subject to the CAIR NOx annual budget, the department shall allocate CAIR NOx hardship allowances under the following procedures:

(a) The department shall establish a hardship allocation set-aside pool for each CAIR NOx annual allocation year for existing EGUs. This hardship set-aside pool shall be allocated on a yearly basis and contains 1,200 tons of CAIR NOx annual allowances per allocation year.

(b) Hardship allowances may be allocated to an EGU or non-EGU, if the requesting authorized account representative demonstrates both of the following:

(i) The owner or operator of the EGU has less than 250 employees within its company or its electric generating division or department.

(ii) The controls required for the EGU under this part result in excessive or prohibitive costs for compliance, pursuant to the procedures in subrule (3) of this rule.

(c) The CAIR authorized account representative of a CAIR NOx unit under this rule may submit to the department a written request, in a format specified by the department, to receive CAIR NOx annual hardship allowances. The authorized account representative shall submit the request for the amount of estimated hardship allowances they need, using historical annual heat input utilization levels multiplied by historical oxides of nitrogen emission rates, in the following manner:

(i) Historical heat input utilization levels shall be based on the unit's average of the 2 highest heat input utilization levels for the annual control period in the 5 years immediately preceding the year in which the department is required to submit the oxides of nitrogen allocations to the U.S. environmental protection agency. If the unit operated less than 2 years during the 5-year time period, then the unit's single highest heat input level shall be used.

(ii) Historic oxides of nitrogen rates shall be based on the oxides of nitrogen rate reported by the authorized account representative in its 40 C.F.R. part 75 reports to the U.S. environmental protection agency in the calendar year immediately preceding the year in which the department is required to submit the oxides of nitrogen allocation.

(iii) Units receiving hardship allowances shall receive a 3-year allocation that is 3 years in advance of the annual control period in which the hardship allowances are to be used. The 3-year allocation shall be the same as provided in R 336.1830(2).

(d) The department shall allocate the allowances based on the requests received as follows:

(i) If the allocation hardship set-aside pool for the CAIR NOx annual control period for which CAIR NOx annual allowances are requested has an amount of oxides of nitrogen allowances greater than or equal to the number requested, then the department shall allocate the amount of the CAIR NOx annual budget allowances requested.

(ii) If the allocation hardship set-aside pool for the CAIR NOx annual control period for which CAIR NOx annual allowances are requested has an amount of oxides of nitrogen allowances less than the number requested, then the department shall proportionately reduce the number of CAIR NOx annual

allowances allocated to each CAIR NOx annual unit so that the total number of CAIR NOx annual allowances allocated are equal to the amounts referenced in subdivision (a) of this subrule.

(3) The department shall allocate CAIR NOx annual hardship allowances to existing CAIR NOx units which have submitted an engineering analysis as described as follows:

(a) The authorized account representative shall demonstrate to the department that the control level required pursuant to this rule results in excessive or prohibitive cost for compliance. The demonstration shall include all of the following:

(i) An engineering study analyzing all control options that are technically available for the unit, including control options that would achieve a level of control meeting, at a minimum, a 0.15 pound per million Btu emission rate.

(ii) The annualized cost associated with each control option. An annualized cost of more than $2,400 per ton of oxides of nitrogen reduced shall generally be considered to be an excessive cost for compliance with this rule.

(iii) Other considerations that contribute to prohibitive cost of compliance.

(b) For a source to remain eligible for hardship allowances under this rule after the initial 3-year allocation period, ending on September 30, 2011, the state may require a revised engineering analysis and demonstration as detailed under subrule (3)(a) of this rule, at a minimum of once every 3 years.

R 336.1833 CAIR NOx annual trading program; compliance supplement pool.

Rule 833. (1) The department shall allow sources required to implement CAIR NOx control measures by January 1, 2009, and subject to this rule to demonstrate compliance using allowances issued from the compliance supplement pool under this rule, as follows:

(a) The total number of CAIR NOx allowances available to existing EGUs, for early reduction purposes from the compliance supplement pool, shall not be more than 6,491 tons of oxides of nitrogen.

(b) The total number of CAIR NOx allowances available for the newly-affected EGUs, for hardship purposes from the compliance supplement pool, shall not be more than 1,856 tons of oxides of nitrogen.

(c) Any CAIR NOx allowances that remain in the compliance supplement pool after the 2009 control period shall be retired.

(d) Sources that receive allowances according to the requirements of this rule may trade the allowance to other sources or persons according to the provisions in the CAIR NOx annual trading program.

(2) The department shall issue early reduction allowances to existing EGUs as follows:

(a) The emissions reduction shall not be required by Michigan's state implementation plan, state law, or rule, or be otherwise required by federal law.

(b) The emissions reduction shall be verified by the source as actually having occurred during the calendar years of 2007 and 2008.

(c) Each CAIR NOx unit for which the owner or operator requests any early reduction allowances under this rule shall monitor oxides of nitrogen emissions under 40 C.F.R. part 75, subpart H, which are adopted by reference in R 336.1802a, starting not less than 1 calendar year before the annual control period for which the early reduction allowances are requested. The unit's monitoring system availability shall be not less than 90 percent during the control period in which monitoring occurs for this purpose and the unit shall be in compliance with any applicable state or federal emissions or emissions-related requirements.

(d) The emissions reduction shall be quantified according to procedures set forth in 40 C.F.R. part 75, subpart H.

(e) The emissions reduction request shall include both of the following:

(i) The CAIR NOx authorized account representative may request early reduction allowances for the annual control period in an amount equal to the unit's heat input for the year, multiplied by the difference between the rates in both of the following provisions, divided by 2,000 pounds per ton, and rounded to the nearest ton:

(A) The oxides of nitrogen emission limit required by Michigan's state implementation plan, otherwise required by the clean air act, or 0.25 pound per million Btu heat input, whichever is most stringent.

(B) The unit's actual oxides of nitrogen emission rate for the 2007 and 2008 calendar years, which shall be lower than the rate used in subparagraph (A) of this paragraph and less than 80% of the actual 2005 annual oxides of nitrogen emission rate, expressed as pound per million Btu heat input.

(ii) The early reduction allowance request shall be submitted in writing, in a format specified by the department, not later than July 1, 2009, for the 2007 and 2008 control periods.

(f) The department shall allocate CAIR NOx allowances to CAIR NOx units meeting the requirements of this subdivision and requesting early reduction allocations, in the following manner:

(i) Upon receipt of each early reduction allowance request, the department shall accept the request only if the requirements of subdivisions (a) to (e) of this subrule are met and, if the request is accepted, shall make any necessary adjustments to the request to ensure that the amount of the early reduction allowances requested meets the requirement of subdivisions (a) to (e) of this subrule.

(ii) If the compliance supplement pool has an amount of CAIR NOx allowances equal to or greater than the number of early reduction allowances in all accepted early reduction allowance requests for 2007 and 2008, as adjusted under paragraph (i) of this subdivision, the department shall allocate to each CAIR NOx unit covered by the accepted requests 1 allowance for each early reduction allowance requested, as adjusted under paragraph (i) of this subdivision.

(iii) If the compliance supplement pool has an amount of CAIR NOx allowances less than the number of early reduction allowances in all accepted early reduction allowance requests for 2007 and 2008, as adjusted under

paragraph (i) of this subdivision, the department shall allocate CAIR NOx allowances to each CAIR NOx unit covered by the accepted requests according to the following formula and rounding to the nearest whole allowance as appropriate:

$$Allocated\ ERC = \left(\frac{Units\ ERC\ requested}{Total\ requested\ ERC}\right) x\ Available\ CAIR\ NOx\ Allowances$$

Where:

ERC =	**Early reduction allowances.**
Allocated ERCs =	**Each unit's allocated early reduction allowances.**
Total requested ERCs =	**The total amount of ERCs requested by all units from the compliance supplement pool.**
Available CAIR NOx Allowances =	**The total amount of allowances available from the early reduction portion of the compliance supplement pool.**

(3) The department shall issue hardship allowances to newly-affected EGUs for which compliance with the CAIR NOx emissions limitations would create an undue risk to the reliability of electricity supply during the 2009 control period. The CAIR NOx authorized account representative of the CAIR NOx unit may request the allocation of CAIR NOx allowances from the compliance supplement pool under subrule (1)(b) of this rule, pursuant to the following:

(a) The CAIR NOx authorized account representative shall submit to the department by July 1, 2009, a written request, in a format specified by the department, for allocation of an amount of CAIR NOx allowances from the compliance supplement pool not exceeding the minimum amount of CAIR NOx allowances necessary to remove the undue risk to the reliability of electricity supply.

(b) The CAIR NOx authorized account representative shall demonstrate that, in the absence of allocation of the amount of CAIR NOx allowances requested, the unit's compliance with the CAIR NOx emissions limitation for the 2009 control period would create an undue risk to the reliability of electricity supply during the 2009 control period. This demonstration shall include both of the following:

(i) A showing that it would not be possible for the owners and operators of the unit to comply with applicable control measures by obtaining sufficient amounts of electricity from other electric generation facilities during the installation of control technology at the unit.

(ii) A showing that it would not be possible for the owners and operators of the unit to comply with applicable control measures by acquiring sufficient allowances from other sources or persons.

(c) The department shall review each request submitted by July 1, 2009, and allocate CAIR NOx allowances for the 2009 control period to requesting Michigan CAIR NOx units as follows:

(i) Upon receipt of each hardship request, the department shall accept the request only if the requirements of subdivisions (a) and (b) of this subrule are

met and, if the request is accepted, shall make any necessary adjustments to the request to ensure that the amount of the CAIR NOx hardship allowances requested meets the requirements of subdivisions (a) and (b) of this subrule.

(ii) If the compliance supplement pool has an amount of CAIR NOx hardship allowances equal to or greater than the number of CAIR NOx allowances in the hardship requests, the department shall allocate to each CAIR NOx unit the amount of CAIR NOx allowances requested, as adjusted under paragraph (i) of this subdivision.

(iii) If the compliance supplement pool has an amount of CAIR NOx allowances less than the number of hardship allowances in all accepted hardship requests, as adjusted under paragraph (i) of this subdivision, the department shall allocate CAIR NOx allowances to each CAIR NOx unit covered by the accepted requests according to the following formula and rounding to the nearest whole allowance as appropriate:

$$Adjusted\ Allocation = \mathrm{Re}quested\ Allocation\quad X \left(\frac{Available\ Pool\ Allocations}{Total\ adjusted\ allocation\ for\ all\ units} \right)$$

Where:

Adjusted allocation =	**The number of CAIR NOx hardship allowances allocated to the unit from the state's compliance supplement pool.**
Requested allocation =	**The amount of CAIR NOx hardship allowances requested for the unit.**
Available pool allocations =	**The amount of CAIR NOx hardship allowances in the state's compliance supplement pool.**
Total adjusted allocations for all units =	**The sum of the amounts of hardship allocations requested for all units, as adjusted.**

(4) The department shall complete its review process not later than September 1, 2009. By November 30, 2009, the department shall determine, and submit to the U.S. environmental protection agency, the allocations under subrules (2) or (3) of this rule.

R 336.1834 Opt-in provisions under the CAIR NOx annual trading program.

Rule 834. The opt-in provisions in 40 C.F.R. §§97.180 through 97.188 are adopted by reference in R 336.1802a and are applicable to this rule.

ATTACHMENT G

	Source information											Annual Values			
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arith. average**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**
Cadillac RE	Cadillac Renew	GEN1	solid		0.15	1.00			3,739,212			3,401,849			3,298,996
CMS Gen/MI Pwr	Kalamazoo River	1	gas	**0.085**	0.15	0.40	**0.07**		16,152			11,849			24,040
CMS Gen/MI Pwr	Livingston Station	001	gas		0.15	0.40			36,696			11,165			24,444
CMS Gen/MI Pwr	Livingston Station	002	gas		0.15	0.40			34,566			11,963			25,673
CMS Gen/MI Pwr	Livingston Station	003	gas		0.15	0.40			34,042			14,776			21,765
CMS Gen/MI Pwr	Livingston Station	004	gas		0.15	0.40			35,690			9,248			21,530
CMS Generation	Genesee Power	GEN1	solid		0.15	1.00			3,119,509			2,989,823			3,262,440
CMS Generation	Grayling Station	GEN1	solid		0.15	1.00			3,393,669			2,893,805			3,301,806
CMS Generation	TES Filer City	B1	solid		0.15	1.00			2,731,978			2,695,191			2,782,690
CMS Generation	TES Filer City	B2	solid		0.15	1.00			2,731,978			2,695,191			2,782,690
Consumers Energy	Campbell	1	solid		0.15	1.00			13,155,517			21,798,697			21,367,302
Consumers Energy	Campbell	2	solid		0.15	1.00			24,125,827			24,312,028			22,594,539
Consumers Energy	Campbell	3	solid		0.15	1.00			62,570,086			53,055,997			67,055,963
Consumers Energy	Cobb	1	gas		0.15	0.40			278,874			185,467			47,190
Consumers Energy	Cobb	2	gas		0.15	0.40			255,344			169,559			47,935
Consumers Energy	Cobb	3	gas		0.15	0.40			306,620			190,193			7,820
Consumers Energy	Cobb	4	solid		0.15	1.00			12,357,348			11,352,929			11,950,163
Consumers Energy	Cobb	5	solid		0.15	1.00			10,219,548			12,591,560			11,499,723
Consumers Energy	Karn	1	solid		0.15	1.00			17,877,384			18,511,275			19,068,898
Consumers Energy	Karn	2	solid		0.15	1.00			20,219,624			20,039,578			16,067,341
Consumers Energy	Karn	3	dual		0.15	0.40		0.48	7,771,450	3,721,584	0.50	6,915,250	3,440,141	0.55	3,361,613
Consumers Energy	Karn	4	dual		0.15	0.40		**0.46**	6,763,915	3,130,677	0.50	4,786,746	2,372,763	0.54	2,576,621
Consumers Energy	Thetford CT	1	gas		0.15	0.40			23,875			20,227			22,049
Consumers Energy	Thetford CT	2	gas		0.15	0.40			18,250			20,168			17,014
Consumers Energy	Thetford CT	3	gas		0.15	0.40			13,958			19,054			19,197
Consumers Energy	Thetford CT	4	gas		0.15	0.40			7,208			12,970			17,918
Consumers Energy	Weadock	7	solid		0.15	1.00			10,420,490			12,239,672			12,822,427
Consumers Energy	Weadock	8	solid		0.15	1.00			14,062,399			11,622,625			12,692,967
Consumers Energy	Whiting	1	solid		0.15	1.00			7,539,106			8,907,503			8,924,762
Consumers Energy	Whiting	2	solid		0.15	1.00			8,759,753			7,879,230			8,503,714
Consumers Energy	Whiting	3	solid		0.15	1.00			9,101,039			10,278,867			9,926,144
Covert Generating LLC	Covert	1	gas	**0.009**	0.15	0.40	**0.03**		0			0			1,872,810
Covert Generating LLC	Covert	2	gas	**0.009**	0.15	0.40	**0.03**		0			0			5,295,970
Covert Generating LLC	Covert	3	gas	**0.009**	0.15	0.40	**0.03**		0			0			1,718,682
Dearborn Ind. Gen.	Dearborn Ind.	B1	gas	**0.1**	0.15	0.40	**0.08**		806,355			2,437,348			2,504,066
Dearborn Ind. Gen.	Dearborn Ind.	B2	gas	**0.1**	0.15	0.40	**0.08**		697,601			2,142,750			2,785,766
Dearborn Ind. Gen.	Dearborn Ind.	B3	gas	**0.1**	0.15	0.40	**0.08**		628,487			2,654,975			2,510,858
Dearborn Ind. Gen.	Dearborn Ind.	GTP1	gas	**0.033**	0.15	0.40	**0.05**		450,275			595,935			67,937
Detroit Edison	Belle River	1	solid		0.15	1.00			52,284,748			55,238,546			39,503,328
Detroit Edison	Belle River	2	solid		0.15	1.00			50,693,844			32,606,529			48,243,589
Detroit Edison	Belle River	CTG121	gas	**0.033**	0.15	0.40	**0.05**		562,427			858,536			401,816
Detroit Edison	Belle River	CTG122	gas	**0.033**	0.15	0.40	**0.05**		401,119			661,034			286,576
Detroit Edison	Belle River	CTG131	gas	**0.033**	0.15	0.40	**0.05**		403,326			580,541			302,417
Detroit Edison	Connors Creek	15	gas		0.15	0.40			264,972			260,081			102,378
Detroit Edison	Connors Creek	16	gas		0.15	0.40			276,197			220,549			74,398
Detroit Edison	Connors Creek	17	gas		0.15	0.40			236,651			146,908			99,776
Detroit Edison	Connors Creek	18	gas		0.15	0.40			265,491			203,715			83,168
Detroit Edison	Delray	CTG111	gas	**0.055**	0.15	0.40	**0.06**		206,339			397,717			233,605
Detroit Edison	Delray	CTG121	gas	**0.055**	0.15	0.40	**0.06**		182,261			383,730			207,170
Detroit Edison	East China	1	gas	**0.036**	0.15	0.40	**0.05**		0			66,874			112,328
Detroit Edison	East China	2	gas	**0.036**	0.15	0.40	**0.05**		0			67,436			93,866
Detroit Edison	East China	3	gas	**0.036**	0.15	0.40	**0.05**		0			85,737			91,329
Detroit Edison	East China	4	gas	**0.036**	0.15	0.40	**0.05**		0			62,264			105,886
Detroit Edison	Greenwood	1	dual		0.15	0.40		0.45	9,673,911	4,362,635	0.48	11,701,703	5,621,270	0.50	6,969,328
Detroit Edison	Greenwood	CTG111	gas	**0.033**	0.15	0.40	**0.05**		438,076			606,876			203,477
Detroit Edison	Greenwood	CTG112	gas	**0.033**	0.15	0.40	**0.05**		320,807			544,587			121,400
Detroit Edison	Greenwood	CTG121	gas	**0.033**	0.15	0.40	**0.05**		342,731			500,185			124,811
Detroit Edison	Hancock	12-1 (5)	gas		0.15	0.40			58,068			27,962			51,901
Detroit Edison	Hancock	12-2 (6)	gas		0.15	0.40			47,967			29,623			51,516
Detroit Edison	Harbor Beach	1	solid		0.15	1.00			2,283,416			2,737,110			2,291,301
Detroit Edison	Marysville	9	solid		0.15	1.00			508,369			0			0

	Source information											Annual Values			
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arith. average**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**
Detroit Edison	Marysville	10	solid		0.15	1.00			406,858			0			0
Detroit Edison	Marysville	11	solid		0.15	1.00			431,617			0			0
Detroit Edison	Marysville	12	solid		0.15	1.00			517,072			0			0
Detroit Edison	Monroe	1	solid		0.15	1.00			31,787,539			37,900,714			36,375,042
Detroit Edison	Monroe	2	solid		0.15	1.00			40,137,687			44,583,407			34,080,756
Detroit Edison	Monroe	3	solid		0.15	1.00			48,668,709			43,377,986			43,799,956
Detroit Edison	Monroe	4	solid		0.15	1.00			50,570,249			32,484,566			54,468,859
Detroit Edison	River Rouge	1	gas		0.15	0.40			736,582			551,706			253,473
Detroit Edison	River Rouge	2	solid		0.15	1.00			9,345,293			18,528,487			15,109,968
Detroit Edison	River Rouge	3	solid		0.15	1.00			15,960,363			15,942,526			13,589,912
Detroit Edison	St. Clair	1	solid		0.15	1.00			8,487,866			9,079,111			7,546,332
Detroit Edison	St. Clair	2	solid		0.15	1.00			9,993,401			5,359,011			4,186,272
Detroit Edison	St. Clair	3	solid		0.15	1.00			7,933,356			9,311,954			8,893,199
Detroit Edison	St. Clair	4	solid		0.15	1.00			8,484,952			9,604,699			8,873,193
Detroit Edison	St. Clair	6	solid		0.15	1.00			17,597,973			17,415,112			14,354,894
Detroit Edison	St. Clair	7	solid		0.15	1.00			8,608,084			22,691,354			26,088,697
Detroit Edison	Trenton Channel	16	solid		0.15	1.00			4,370,089			4,332,832			4,129,570
Detroit Edison	Trenton Channel	17	solid		0.15	1.00			4,106,432			4,346,912			4,317,456
Detroit Edison	Trenton Channel	18	solid		0.15	1.00			4,331,407			4,081,311			3,731,234
Detroit Edison	Trenton Channel	19	solid		0.15	1.00			4,408,814			3,688,673			4,162,144
Detroit Edison	Trenton Channel	9A	solid		0.15	1.00			28,407,802			29,653,709			24,008,693
Detroit PLD	Mistersky	5	gas		0.15	0.40			2,070,750			3,191,905			3,460,811
Detroit PLD	Mistersky	6	gas		0.15	0.40			3,140,297			0			0
Detroit PLD	Mistersky	7	gas		0.15	0.40			5,097,835			2,806,482			2,980,302
Detroit PLD	Mistersky	GT-1	liquid		0.15	0.60			0			0			181,548
Dynegy	Renaissance	CT1	gas	**0.055**	0.15	0.40	**0.06**		0			841,395			273,356
Dynegy	Renaissance	CT2	gas	**0.055**	0.15	0.40	**0.06**		0			715,802			301,577
Dynegy	Renaissance	CT3	gas	**0.055**	0.15	0.40	**0.06**		0			0			232,760
Dynegy	Renaissance	CT4	gas	**0.055**	0.15	0.40	**0.06**		0			670,238			263,805
FirstEnergy Genco	Sumpter	1	gas		0.15	0.40			0			452,170			166,862
FirstEnergy Genco	Sumpter	2	gas		0.15	0.40			0			392,970			166,065
FirstEnergy Genco	Sumpter	3	gas		0.15	0.40			0			399,361			171,321
FirstEnergy Genco	Sumpter	4	gas		0.15	0.40			0			438,019			128,865
Grand Haven BLP	Sims	3	solid		0.15	1.00			4,365,200			2,926,603			3,964,594
Holland BPW	48th Street	7	gas		0.15	0.40			151,225			310,743			72,621
Holland BPW	48th Street	8	gas		0.15	0.40			47,964			97,091			57,104
Holland BPW	48th Street	9	gas	**0.081**	0.15	0.40	**0.07**		392,477			719,906			330,582
Holland BPW	De Young	5	solid		0.15	1.00			2,287,121			1,905,187			2,327,238
Kinder Morgan	Jackson Power	7EA	gas	**0.033**	0.15	0.40	**0.05**		0			963,486			227,749
Kinder Morgan	Jackson Power	LM1	gas	**0.081**	0.15	0.40	**0.07**		0			419,567			98,610
Kinder Morgan	Jackson Power	LM2	gas	**0.081**	0.15	0.40	**0.07**		0			407,496			91,865
Kinder Morgan	Jackson Power	LM3	gas	**0.081**	0.15	0.40	**0.07**		0			263,485			89,200
Kinder Morgan	Jackson Power	LM4	gas	**0.081**	0.15	0.40	**0.07**		0			398,951			85,436
Kinder Morgan	Jackson Power	LM5	gas	**0.081**	0.15	0.40	**0.07**		0			409,984			89,013
Kinder Morgan	Jackson Power	LM6	gas	**0.081**	0.15	0.40	**0.07**		0			385,428			85,759
Lansing BWL	Eckert Station	1	solid		0.15	1.00			2,193,141			2,390,490			2,735,145
Lansing BWL	Eckert Station	2	solid		0.15	1.00			2,250,051			2,200,642			1,516,592
Lansing BWL	Eckert Station	3	solid		0.15	1.00			1,794,677			3,015,535			2,491,150
Lansing BWL	Eckert Station	4	solid		0.15	1.00			5,135,689			5,455,215			5,541,731
Lansing BWL	Eckert Station	5	solid		0.15	1.00			5,210,424			4,409,146			4,689,097
Lansing BWL	Eckert Station	6	solid		0.15	1.00			4,270,493			4,498,764			5,018,062
Lansing BWL	Erickson	1	solid		0.15	1.00			7,364,811			8,726,322			9,905,662
Marquette. City of	Shiras	3	solid		0.15	1.00			3,897,490			3,551,115			3,793,130
Michigan Power LP	MI Power LP	G101	gas	**0.05**	0.15	0.40	**0.06**		8,158,601			9,614,040			10,029,672
Michigan Public Pwr	Kalkaska CT #1	1A	gas	**0.092**	0.15	0.40	**0.08**		0			0			46,508
Michigan Public Pwr	Kalkaska CT #1	1B	gas	**0.092**	0.15	0.40	**0.08**		0			0			55,074
Midland Cogen V.	Midland Cogen V.	GT10	gas	**0.149**	0.15	0.40	**0.10**		6,248,493			5,591,400			5,019,880
Midland Cogen V.	Midland Cogen V.	GT11	gas	**0.149**	0.15	0.40	**0.10**		6,871,055			5,670,918			5,174,188
Midland Cogen V.	Midland Cogen V.	GT12	gas	**0.1**	0.15	0.40	**0.08**		6,373,823			5,027,637			4,577,762
Midland Cogen V.	Midland Cogen V.	GT13	gas	**0.149**	0.15	0.40	**0.10**		7,278,544			6,070,442			5,595,108
Midland Cogen V.	Midland Cogen V.	GT14	gas	**0.149**	0.15	0.40	**0.10**		6,244,846			6,440,071			5,842,690

	Source information											Annual Values			
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-2014**	**Fuel Adj Factor**	**Arith. average**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**
Midland Cogen V.	Midland Cogen V.	GT3	gas	**0.149**	0.15	0.40	**0.10**		6,265,292			7,626,419			6,212,930
Midland Cogen V.	Midland Cogen V.	GT4	gas	**0.149**	0.15	0.40	**0.10**		7,326,288			6,473,233			5,867,439
Midland Cogen V.	Midland Cogen V.	GT5	gas	**0.149**	0.15	0.40	**0.10**		5,643,725			6,229,356			5,658,507
Midland Cogen V.	Midland Cogen V.	GT6	gas	**0.149**	0.15	0.40	**0.10**		5,759,330			6,916,087			6,245,468
Midland Cogen V.	Midland Cogen V.	GT7	gas	**0.149**	0.15	0.40	**0.10**		6,640,841			5,807,441			5,366,555
Midland Cogen V.	Midland Cogen V.	GT8	gas	**0.149**	0.15	0.40	**0.10**		7,667,023			6,480,616			5,815,477
Midland Cogen V.	Midland Cogen V.	GT9	gas	**0.149**	0.15	0.40	**0.10**		6,670,350			5,982,573			5,108,127
Mirant Zeeland	Zeeland Power	1	gas	**0.04**	0.15	0.40	**0.05**		715,823			512,684			116,802
Mirant Zeeland	Zeeland Power	2	gas	**0.04**	0.15	0.40	**0.05**		612,469			544,687			120,034
Mirant Zeeland	Zeeland Power	3	gas	**0.013**	0.15	0.40	**0.04**		0			1,318,948			1,282,492
Mirant Zeeland	Zeeland Power	4	gas	**0.013**	0.15	0.40	**0.04**		0			1,131,993			1,170,521
MSCPA	Enidcott Gen St	1	solid		0.15	1.00			4,552,863			4,907,732			5,416,634
WE Energies	Presque Isle	2	solid		0.15	1.00			878,397			56,936			472,939
WE Energies	Presque Isle	3	solid		0.15	1.00			3,307,534			3,576,072			3,272,809
WE Energies	Presque Isle	4	solid		0.15	1.00			4,170,172			2,869,877			3,904,275
WE Energies	Presque Isle	5	solid		0.15	1.00			5,506,259			6,084,423			4,214,515
WE Energies	Presque Isle	6	solid		0.15	1.00			6,479,197			5,194,678			5,527,597
WE Energies	Presque Isle	7	solid		0.15	1.00			6,275,974			6,288,693			6,381,585
WE Energies	Presque Isle	8	solid		0.15	1.00			6,179,041			6,527,325			6,086,858
WE Energies	Presque Isle	9	solid		0.15	1.00			6,120,605			6,530,974			5,654,869
Wyandotte DMS	Wyandotte	5	gas		0.15	0.40			12,627			315,993			9,047
Wyandotte DMS	Wyandotte	7	solid		0.15	1.00			2,408,007			2,022,617			2,297,856
Wyandotte DMS	Wyandotte	8	solid		0.15	1.00			1,470,385			1,359,241			1,415,637

Corrections to the numbers include rounding up if greater than 0.5 to reach the target of 63,104

Source information										Calculations				
Company Name	Plant Name	Unit ID	2003 Adjusted Heat Input	2004 Fuel Ratio	2004 Heat Input	2004 Adjusted Heat Input	2005 Fuel Ratio	2005 Heat Input	2005 Adjusted Heat Input	Highest 2 year average	Calc'd CAIR	Adjusted 2010 CAIR	Corrected (Rounding) 2009	Corrected (Rounding) 2010
Cadillac RE	Cadillac Renew	GEN1			3,409,205			3,382,278		3,574,209	268	252	**252**	**252**
CMS Gen/MI Pwr	Kalamazoo River	1			68,053			164,296		116,175	4	4	**4**	**4**
CMS Gen/MI Pwr	Livingston Station	001			17,606			97,869		67,283	2	2	**2**	**2**
CMS Gen/MI Pwr	Livingston Station	002			16,443			91,409		62,988	2	2	**2**	**2**
CMS Gen/MI Pwr	Livingston Station	003			7,904			112,305		73,174	2	2	**2**	**2**
CMS Gen/MI Pwr	Livingston Station	004			16,698			91,463		63,577	2	2	**2**	**2**
CMS Generation	Genesee Power	GEN1			3,756,273			3,773,719		3,764,996	282	265	**265**	**265**
CMS Generation	Grayling Station	GEN1			3,924,770			3,597,115		3,760,943	282	265	**265**	**265**
CMS Generation	TES Filer City	B1			3,151,616			2,879,646		3,015,631	226	213	**213**	**213**
CMS Generation	TES Filer City	B2			3,151,616			2,879,646		3,015,631	226	213	**213**	**213**
Consumers Energy	Campbell	1			19,732,030			21,297,843		21,583,000	1,619	1,521	**1,521**	**1,521**
Consumers Energy	Campbell	2			21,102,965			21,630,551		24,218,928	1,816	1,707	**1,707**	**1,707**
Consumers Energy	Campbell	3			55,140,163			58,757,120		64,813,025	4,861	4,568	**4,568**	**4,568**
Consumers Energy	Cobb	1			295			241,779		260,327	8	7	**7**	**7**
Consumers Energy	Cobb	2			227			231,899		243,622	7	7	**7**	**7**
Consumers Energy	Cobb	3			133			209,770		258,195	8	7	**7**	**7**
Consumers Energy	Cobb	4			11,677,146			9,111,205		12,153,756	912	857	**857**	**857**
Consumers Energy	Cobb	5			11,527,460			13,644,417		13,117,989	984	925	**925**	**925**
Consumers Energy	Karn	1			15,836,937			20,199,031		19,633,965	1,473	1,384	**1,384**	**1,384**
Consumers Energy	Karn	2			20,141,106			19,801,360		20,180,365	1,514	1,422	**1,422**	**1,422**
Consumers Energy	Karn	3	1,832,201	0.57	2,984,763	1,698,688	0.50	4,655,426	2,315,545	3,580,863	269	252	**252**	**252**
Consumers Energy	Karn	4	1,395,176	0.58	1,124,380	646,563	0.48	3,554,310	1,711,656	2,751,720	206	194	**194**	**194**
Consumers Energy	Thetford CT	1			4,749			106,749		65,312	2	2	**2**	**2**
Consumers Energy	Thetford CT	2			10,671			114,759		67,464	2	2	**2**	**2**
Consumers Energy	Thetford CT	3			6,575			110,754		64,976	2	2	**2**	**2**
Consumers Energy	Thetford CT	4			6,191			122,786		70,352	2	2	**2**	**2**
Consumers Energy	Weadock	7			9,132,977			10,539,997		12,531,050	940	883	**883**	**883**
Consumers Energy	Weadock	8			12,303,429			12,225,783		13,377,683	1,003	943	**943**	**943**
Consumers Energy	Whiting	1			8,555,544			8,904,390		8,916,133	669	628	**628**	**628**
Consumers Energy	Whiting	2			8,571,610			9,265,577		9,012,665	676	635	**635**	**635**
Consumers Energy	Whiting	3			10,715,793			9,220,343		10,497,330	787	740	**740**	**740**
Covert Generating LLC	Covert	1			632,297			1,934,155		1,903,483	33	31	**31**	**31**
Covert Generating LLC	Covert	2			747,296			2,114,060		3,705,015	64	60	**60**	**60**
Covert Generating LLC	Covert	3			1,854,637			2,583,525		2,219,081	38	36	**36**	**36**
Dearborn Ind. Gen.	Dearborn Ind.	B1			2,890,126			3,644,590		3,267,358	131	123	**123**	**123**
Dearborn Ind. Gen.	Dearborn Ind.	B2			2,398,019			3,451,792		3,118,779	125	117	**117**	**117**
Dearborn Ind. Gen.	Dearborn Ind.	B3			2,895,188			3,682,266		3,288,727	132	124	**124**	**124**
Dearborn Ind. Gen.	Dearborn Ind.	GTP1			292,107			2,048,956		1,322,446	31	29	**29**	**29**
Detroit Edison	Belle River	1			47,984,884			43,592,569		53,761,647	4,032	3,789	**3,789**	**3,789**
Detroit Edison	Belle River	2			48,332,026			40,500,914		49,512,935	3,713	3,489	**3,489**	**3,489**
Detroit Edison	Belle River	CTG121			197,046			617,886		738,211	17	16	**16**	**16**
Detroit Edison	Belle River	CTG122			137,252			608,169		634,602	15	14	**14**	**14**
Detroit Edison	Belle River	CTG131			120,636			605,990		593,266	14	13	**13**	**13**
Detroit Edison	Connors Creek	15			146,630			389,921		327,447	10	9	**9**	**9**
Detroit Edison	Connors Creek	16			105,008			317,876		297,037	9	8	**8**	**8**
Detroit Edison	Connors Creek	17			143,831			282,956		259,804	8	7	**7**	**7**
Detroit Edison	Connors Creek	18			131,985			326,422		295,957	9	8	**8**	**8**
Detroit Edison	Delray	CTG111			152,365			344,895		371,306	11	10	**10**	**10**
Detroit Edison	Delray	CTG121			183,282			414,814		399,272	11	11	**11**	**11**
Detroit Edison	East China	1			0			265,296		188,812	5	4	**4**	**4**
Detroit Edison	East China	2			0			272,178		183,022	4	4	**4**	**4**
Detroit Edison	East China	3			0			293,095		192,212	5	4	**4**	**4**
Detroit Edison	East China	4			0			267,345		186,616	4	4	**4**	**4**
Detroit Edison	Greenwood	1	3,479,269	0.54	5,501,890	2,974,885	0.49	7,927,441	3,874,973	4,991,953	374	352	**352**	**352**
Detroit Edison	Greenwood	CTG111			24,408			542,453		574,665	13	13	**13**	**13**
Detroit Edison	Greenwood	CTG112			25,263			546,583		545,585	13	12	**12**	**12**
Detroit Edison	Greenwood	CTG121			23,250			180,528		421,458	10	9	**9**	**9**
Detroit Edison	Hancock	12-1 (5)			6,585			19,770		54,985	2	2	**2**	**2**
Detroit Edison	Hancock	12-2 (6)			6,108			6,185		49,742	1	1	**1**	**1**
Detroit Edison	Harbor Beach	1			2,525,983			3,805,441		3,271,276	245	231	**231**	**231**
Detroit Edison	Marysville	9			0			0		254,185	19	18	**18**	**18**

	Source information									Calculations				
Company Name	**Plant Name**	**Unit ID**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**	**2004 Adjusted Heat Input**	**2005 Fuel Ratio**	**2005 Heat Input**	**2005 Adjusted Heat Input**	**Highest 2 year average**	**Calc'd CAIR**	**Adjusted 2010 CAIR**	**Corrected (Rounding) 2009**	**Corrected (Rounding) 2010**
Detroit Edison	Marysville	10			0			0		203,429	15	14	**14**	**14**
Detroit Edison	Marysville	11			0			0		215,809	16	15	**15**	**15**
Detroit Edison	Marysville	12			0			0		258,536	19	18	**18**	**18**
Detroit Edison	Monroe	1			41,328,125			44,433,797		42,880,961	3,216	3,022	**3,022**	**3,022**
Detroit Edison	Monroe	2			39,069,142			37,320,815		42,360,547	3,177	2,985	**2,985**	**2,985**
Detroit Edison	Monroe	3			28,379,861			46,055,494		47,362,102	3,552	3,338	**3,338**	**3,338**
Detroit Edison	Monroe	4			49,753,246			48,732,751		52,519,554	3,939	3,701	**3,701**	**3,701**
Detroit Edison	River Rouge	1			18,092			58,024		644,144	19	18	**18**	**18**
Detroit Edison	River Rouge	2			17,182,775			15,915,215		17,855,631	1,339	1,258	**1,258**	**1,258**
Detroit Edison	River Rouge	3			17,245,980			12,365,866		16,603,172	1,245	1,170	**1,170**	**1,170**
Detroit Edison	St. Clair	1			9,024,092			8,297,906		9,051,602	679	638	**638**	**638**
Detroit Edison	St. Clair	2			9,145,258			8,434,530		9,569,330	718	674	**674**	**674**
Detroit Edison	St. Clair	3			7,040,417			8,209,177		9,102,577	683	642	**642**	**642**
Detroit Edison	St. Clair	4			7,241,706			9,583,774		9,594,237	720	676	**676**	**676**
Detroit Edison	St. Clair	6			19,239,917			17,931,580		18,585,749	1,394	1,310	**1,310**	**1,310**
Detroit Edison	St. Clair	7			25,930,296			23,592,556		26,009,497	1,951	1,833	**1,833**	**1,833**
Detroit Edison	Trenton Channel	16			5,155,720			4,337,513		4,762,905	357	336	**336**	**336**
Detroit Edison	Trenton Channel	17			4,801,287			4,410,672		4,605,980	345	325	**325**	**325**
Detroit Edison	Trenton Channel	18			4,943,593			4,027,943		4,637,500	348	327	**327**	**327**
Detroit Edison	Trenton Channel	19			4,955,719			4,193,209		4,682,267	351	330	**330**	**330**
Detroit Edison	Trenton Channel	9A			27,463,430			27,170,088		29,030,756	2,177	2,046	**2,046**	**2,046**
Detroit PLD	Mistersky	5			3,666,011			1,625,181		3,563,411	107	100	**100**	**100**
Detroit PLD	Mistersky	6			267,086			2,292,907		2,716,602	81	77	**77**	**77**
Detroit PLD	Mistersky	7			2,728,105			2,841,319		4,039,069	121	114	**114**	**114**
Detroit PLD	Mistersky	GT-1			34,163			27,442		107,856	5	5	**5**	**5**
Dynegy	Renaissance	CT1			554,974			1,129,782		985,589	28	27	**27**	**27**
Dynegy	Renaissance	CT2			61,334			1,045,517		880,660	25	24	**24**	**24**
Dynegy	Renaissance	CT3			89,798			1,490,111		861,436	25	23	**23**	**23**
Dynegy	Renaissance	CT4			91,559			1,540,285		1,105,262	32	30	**30**	**30**
FirstEnergy Genco	Sumpter	1			63,531			391,675		421,923	13	12	**12**	**12**
FirstEnergy Genco	Sumpter	2			57,361			412,947		402,959	12	11	**11**	**11**
FirstEnergy Genco	Sumpter	3			61,233			402,273		400,817	12	11	**11**	**11**
FirstEnergy Genco	Sumpter	4			56,513			427,602		432,811	13	12	**12**	**12**
Grand Haven BLP	Sims	3			3,497,186			4,576,267		4,470,734	335	315	**315**	**315**
Holland BPW	48th Street	7			87,520			60,364		230,984	7	7	**7**	**7**
Holland BPW	48th Street	8			8,012			39,430		77,098	2	2	**2**	**2**
Holland BPW	48th Street	9			171,618			99,726		556,192	20	18	**18**	**18**
Holland BPW	De Young	5			1,996,348			1,923,751		2,307,180	173	163	**163**	**163**
Kinder Morgan	Jackson Power	7EA			100,155			820,209		891,848	21	19	**19**	**19**
Kinder Morgan	Jackson Power	LM1			47,821			200,621		310,094	11	10	**10**	**10**
Kinder Morgan	Jackson Power	LM2			51,946			220,775		314,136	11	10	**10**	**10**
Kinder Morgan	Jackson Power	LM3			31,916			272,143		267,814	9	9	**9**	**9**
Kinder Morgan	Jackson Power	LM4			44,937			203,757		301,354	11	10	**10**	**10**
Kinder Morgan	Jackson Power	LM5			37,494			285,472		347,728	12	12	**12**	**12**
Kinder Morgan	Jackson Power	LM6			34,751			219,895		302,662	11	10	**10**	**10**
Lansing BWL	Eckert Station	1			2,234,063			2,670,370		2,702,758	203	190	**190**	**190**
Lansing BWL	Eckert Station	2			2,786,797			2,620,806		2,703,802	203	191	**191**	**191**
Lansing BWL	Eckert Station	3			2,826,199			2,945,059		2,980,297	224	210	**210**	**210**
Lansing BWL	Eckert Station	4			4,850,228			3,146,285		5,498,473	412	388	**388**	**388**
Lansing BWL	Eckert Station	5			5,181,326			3,953,871		5,195,875	390	366	**366**	**366**
Lansing BWL	Eckert Station	6			4,918,205			5,312,448		5,165,255	387	364	**364**	**364**
Lansing BWL	Erickson	1			8,880,260			11,920,080		10,912,871	818	769	**769**	**769**
Marquette. City of	Shiras	3			3,387,485			3,500,784		3,845,310	288	271	**271**	**271**
Michigan Power LP	MI Power LP	G101			9,784,452			10,357,229		10,193,451	280	263	**263**	**263**
Michigan Public Pwr	Kalkaska CT #1	1A			88,499			35,209		67,504	3	2	**3**	**3**
Michigan Public Pwr	Kalkaska CT #1	1B			70,999			45,072		63,037	2	2	**3**	**3**
Midland Cogen V.	Midland Cogen V.	GT10			8,111,834			**3,632,000**		7,180,164	375	353	**353**	**353**
Midland Cogen V.	Midland Cogen V.	GT11			8,276,253			**3,097,543**		7,573,654	396	372	**372**	**372**
Midland Cogen V.	Midland Cogen V.	GT12			7,212,935			**2,351,798**		6,793,379	272	255	**255**	**255**
Midland Cogen V.	Midland Cogen V.	GT13			7,474,816			**5,822,636**		7,376,680	385	362	**362**	**362**
Midland Cogen V.	Midland Cogen V.	GT14			6,927,472			**6,958,488**		6,942,980	363	341	**341**	**341**

	Source information										Calculations				
Company Name	Plant Name	Unit ID	2003 Adjusted Heat Input	2004 Fuel Ratio	2004 Heat Input	2004 Adjusted Heat Input	2005 Fuel Ratio	2005 Heat Input	2005 Adjusted Heat Input	Highest 2 year average	Calc'd CAIR	Adjusted 2010 CAIR	Corrected (Rounding) 2009	Corrected (Rounding) 2010
Midland Cogen V.	Midland Cogen V.	GT3			8,146,665			**7,130,236**		7,886,542	412	387	**387**	**387**
Midland Cogen V.	Midland Cogen V.	GT4			7,461,836			**6,000,346**		7,394,062	386	363	**363**	**363**
Midland Cogen V.	Midland Cogen V.	GT5			6,981,125			**5,120,373**		6,605,241	345	324	**324**	**324**
Midland Cogen V.	Midland Cogen V.	GT6			7,300,661			**6,524,064**		7,108,374	371	349	**349**	**349**
Midland Cogen V.	Midland Cogen V.	GT7			8,335,206			**4,839,798**		7,488,024	391	368	**368**	**368**
Midland Cogen V.	Midland Cogen V.	GT8			8,290,856			**3,462,938**		7,978,940	417	392	**392**	**392**
Midland Cogen V.	Midland Cogen V.	GT9			7,879,375			**3,706,338**		7,274,863	380	357	**357**	**357**
Mirant Zeeland	Zeeland Power	1			21,509			319,883		614,254	15	14	**14**	**14**
Mirant Zeeland	Zeeland Power	2			46,340			245,681		578,578	14	14	**14**	**14**
Mirant Zeeland	Zeeland Power	3			777,561			2,368,447		1,843,698	34	32	**32**	**32**
Mirant Zeeland	Zeeland Power	4			564,348			2,588,067		1,879,294	34	32	**32**	**32**
MSCPA	Enidcott Gen St	1			5,447,333			6,321,768		5,884,551	441	415	**415**	**415**
WE Energies	Presque Isle	2			493,179			649,913		764,155	57	54	**54**	**54**
WE Energies	Presque Isle	3			3,848,254			3,894,294		3,871,274	290	273	**273**	**273**
WE Energies	Presque Isle	4			4,161,716			4,348,069		4,259,121	319	300	**300**	**300**
WE Energies	Presque Isle	5			5,700,616			5,817,350		5,950,887	446	419	**419**	**419**
WE Energies	Presque Isle	6			5,437,202			5,358,834		6,003,397	450	423	**423**	**423**
WE Energies	Presque Isle	7			5,506,930			7,309,610		6,845,598	513	482	**482**	**482**
WE Energies	Presque Isle	8			6,707,966			6,260,422		6,617,646	496	466	**466**	**466**
WE Energies	Presque Isle	9			6,569,457			6,397,620		6,550,216	491	462	**462**	**462**
Wyandotte DMS	Wyandotte	5			0			0		164,310	5	5	**5**	**5**
Wyandotte DMS	Wyandotte	7			2,535,120			2,780,422		2,657,771	199	187	**187**	**187**
Wyandotte DMS	Wyandotte	8			1,603,407			1,869,950		1,736,679	130	122	**122**	**122**
Corrections to the numbers include rounding up if greater tha											**67,155**	**63,104**	**63,104**	**63,104**

Source information			
Company Name	**Plant Name**	**Unit ID**	**Corrected (Rounding) 2011**
Cadillac RE	Cadillac Renew	GEN1	**252**
CMS Gen/MI Pwr	Kalamazoo River	1	**4**
CMS Gen/MI Pwr	Livingston Station	001	**2**
CMS Gen/MI Pwr	Livingston Station	002	**2**
CMS Gen/MI Pwr	Livingston Station	003	**2**
CMS Gen/MI Pwr	Livingston Station	004	**2**
CMS Generation	Genesee Power	GEN1	**265**
CMS Generation	Grayling Station	GEN1	**265**
CMS Generation	TES Filer City	B1	**213**
CMS Generation	TES Filer City	B2	**213**
Consumers Energy	Campbell	1	**1,521**
Consumers Energy	Campbell	2	**1,707**
Consumers Energy	Campbell	3	**4,568**
Consumers Energy	Cobb	1	**7**
Consumers Energy	Cobb	2	**7**
Consumers Energy	Cobb	3	**7**
Consumers Energy	Cobb	4	**857**
Consumers Energy	Cobb	5	**925**
Consumers Energy	Karn	1	**1,384**
Consumers Energy	Karn	2	**1,422**
Consumers Energy	Karn	3	**252**
Consumers Energy	Karn	4	**194**
Consumers Energy	Thetford CT	1	**2**
Consumers Energy	Thetford CT	2	**2**
Consumers Energy	Thetford CT	3	**2**
Consumers Energy	Thetford CT	4	**2**
Consumers Energy	Weadock	7	**883**
Consumers Energy	Weadock	8	**943**
Consumers Energy	Whiting	1	**628**
Consumers Energy	Whiting	2	**635**
Consumers Energy	Whiting	3	**740**
Covert Generating LLC	Covert	1	**31**
Covert Generating LLC	Covert	2	**60**
Covert Generating LLC	Covert	3	**36**
Dearborn Ind. Gen.	Dearborn Ind.	B1	**123**
Dearborn Ind. Gen.	Dearborn Ind.	B2	**117**
Dearborn Ind. Gen.	Dearborn Ind.	B3	**124**
Dearborn Ind. Gen.	Dearborn Ind.	GTP1	**29**
Detroit Edison	Belle River	1	**3,789**
Detroit Edison	Belle River	2	**3,489**
Detroit Edison	Belle River	CTG121	**16**
Detroit Edison	Belle River	CTG122	**14**
Detroit Edison	Belle River	CTG131	**13**
Detroit Edison	Connors Creek	15	**9**
Detroit Edison	Connors Creek	16	**8**
Detroit Edison	Connors Creek	17	**7**
Detroit Edison	Connors Creek	18	**8**
Detroit Edison	Delray	CTG111	**10**
Detroit Edison	Delray	CTG121	**11**
Detroit Edison	East China	1	**4**
Detroit Edison	East China	2	**4**
Detroit Edison	East China	3	**4**
Detroit Edison	East China	4	**4**
Detroit Edison	Greenwood	1	**352**
Detroit Edison	Greenwood	CTG111	**13**
Detroit Edison	Greenwood	CTG112	**12**
Detroit Edison	Greenwood	CTG121	**9**
Detroit Edison	Hancock	12-1 (5)	**2**
Detroit Edison	Hancock	12-2 (6)	**1**
Detroit Edison	Harbor Beach	1	**231**
Detroit Edison	Marysville	9	**18**

Source information			
Company Name	**Plant Name**	**Unit ID**	**Corrected (Rounding) 2011**
Detroit Edison	Marysville	10	**14**
Detroit Edison	Marysville	11	**15**
Detroit Edison	Marysville	12	**18**
Detroit Edison	Monroe	1	**3,022**
Detroit Edison	Monroe	2	**2,985**
Detroit Edison	Monroe	3	**3,338**
Detroit Edison	Monroe	4	**3,701**
Detroit Edison	River Rouge	1	**18**
Detroit Edison	River Rouge	2	**1,258**
Detroit Edison	River Rouge	3	**1,170**
Detroit Edison	St. Clair	1	**638**
Detroit Edison	St. Clair	2	**674**
Detroit Edison	St. Clair	3	**642**
Detroit Edison	St. Clair	4	**676**
Detroit Edison	St. Clair	6	**1,310**
Detroit Edison	St. Clair	7	**1,833**
Detroit Edison	Trenton Channel	16	**336**
Detroit Edison	Trenton Channel	17	**325**
Detroit Edison	Trenton Channel	18	**327**
Detroit Edison	Trenton Channel	19	**330**
Detroit Edison	Trenton Channel	9A	**2,046**
Detroit PLD	Mistersky	5	**100**
Detroit PLD	Mistersky	6	**77**
Detroit PLD	Mistersky	7	**114**
Detroit PLD	Mistersky	GT-1	**5**
Dynegy	Renaissance	CT1	**27**
Dynegy	Renaissance	CT2	**24**
Dynegy	Renaissance	CT3	**23**
Dynegy	Renaissance	CT4	**30**
FirstEnergy Genco	Sumpter	1	**12**
FirstEnergy Genco	Sumpter	2	**11**
FirstEnergy Genco	Sumpter	3	**11**
FirstEnergy Genco	Sumpter	4	**12**
Grand Haven BLP	Sims	3	**315**
Holland BPW	48th Street	7	**7**
Holland BPW	48th Street	8	**2**
Holland BPW	48th Street	9	**18**
Holland BPW	De Young	5	**163**
Kinder Morgan	Jackson Power	7EA	**19**
Kinder Morgan	Jackson Power	LM1	**10**
Kinder Morgan	Jackson Power	LM2	**10**
Kinder Morgan	Jackson Power	LM3	**9**
Kinder Morgan	Jackson Power	LM4	**10**
Kinder Morgan	Jackson Power	LM5	**12**
Kinder Morgan	Jackson Power	LM6	**10**
Lansing BWL	Eckert Station	1	**190**
Lansing BWL	Eckert Station	2	**191**
Lansing BWL	Eckert Station	3	**210**
Lansing BWL	Eckert Station	4	**388**
Lansing BWL	Eckert Station	5	**366**
Lansing BWL	Eckert Station	6	**364**
Lansing BWL	Erickson	1	**769**
Marquette. City of	Shiras	3	**271**
Michigan Power LP	MI Power LP	G101	**263**
Michigan Public Pwr	Kalkaska CT #1	1A	**3**
Michigan Public Pwr	Kalkaska CT #1	1B	**3**
Midland Cogen V.	Midland Cogen V.	GT10	**353**
Midland Cogen V.	Midland Cogen V.	GT11	**372**
Midland Cogen V.	Midland Cogen V.	GT12	**255**
Midland Cogen V.	Midland Cogen V.	GT13	**362**
Midland Cogen V.	Midland Cogen V.	GT14	**341**

Source information			
Company Name	**Plant Name**	**Unit ID**	**Corrected (Rounding) 2011**
Midland Cogen V.	Midland Cogen V.	GT3	**387**
Midland Cogen V.	Midland Cogen V.	GT4	**363**
Midland Cogen V.	Midland Cogen V.	GT5	**324**
Midland Cogen V.	Midland Cogen V.	GT6	**349**
Midland Cogen V.	Midland Cogen V.	GT7	**368**
Midland Cogen V.	Midland Cogen V.	GT8	**392**
Midland Cogen V.	Midland Cogen V.	GT9	**357**
Mirant Zeeland	Zeeland Power	1	**14**
Mirant Zeeland	Zeeland Power	2	**14**
Mirant Zeeland	Zeeland Power	3	**32**
Mirant Zeeland	Zeeland Power	4	**32**
MSCPA	Enidcott Gen St	1	**415**
WE Energies	Presque Isle	2	**54**
WE Energies	Presque Isle	3	**273**
WE Energies	Presque Isle	4	**300**
WE Energies	Presque Isle	5	**419**
WE Energies	Presque Isle	6	**423**
WE Energies	Presque Isle	7	**482**
WE Energies	Presque Isle	8	**466**
WE Energies	Presque Isle	9	**462**
Wyandotte DMS	Wyandotte	5	**5**
Wyandotte DMS	Wyandotte	7	**187**
Wyandotte DMS	Wyandotte	8	**122**
Corrections to the numbers include rounding up if greater tha			**63,104**

	Source information		Operations Data									Ozone Season Values						
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-14**	**Fuel Adj Factor**	**Arith. Ave.**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**
Cadillac RE	Cadillac Renew	GEN1	solid		0.15	1.00			1,567,395			1,425,980			1,382,867			1,429,064
CMS Gen/MI Pwr	Kalamazoo River	1	gas	**0.085**	0.15	0.40	**0.07**		15,852			9,065			23,332			57,415
CMS Gen/MI Pwr	Livingston Station	001	gas		0.15	0.40			36,183			10,364			21,187			17,436
CMS Gen/MI Pwr	Livingston Station	002	gas		0.15	0.40			34,314			11,323			22,562			16,274
CMS Gen/MI Pwr	Livingston Station	003	gas		0.15	0.40			33,363			14,140			21,436			7,605
CMS Gen/MI Pwr	Livingston Station	004	gas		0.15	0.40			34,952			8,070			21,498			16,378
CMS Generation	Genesee Power	GEN1	solid		0.15	1.00			1,475,225			1,372,514			1,292,849			1,241,432
CMS Generation	Grayling Station	GEN1	solid		0.15	1.00			1,543,980			1,201,820			1,346,391			1,638,608
CMS Generation	TES Filer City	B1	solid		0.15	1.00			1,336,192			1,106,298			1,156,981			1,372,265
CMS Generation	TES Filer City	B2	solid		0.15	1.00			1,336,192			1,106,298			1,156,981			1,372,265
Consumers Energy	Campbell	1	solid		0.15	1.00			5,825,632			9,656,016			9,264,652			9,129,636
Consumers Energy	Campbell	2	solid		0.15	1.00			9,766,936			10,786,454			9,478,872			8,587,536
Consumers Energy	Campbell	3	solid		0.15	1.00			27,634,659			25,298,815			26,346,455			21,541,781
Consumers Energy	Cobb	1	gas		0.15	0.40			238,349			176,489			47,190			295
Consumers Energy	Cobb	2	gas		0.15	0.40			219,116			164,021			47,935			227
Consumers Energy	Cobb	3	gas		0.15	0.40			269,215			179,793			7,820			133
Consumers Energy	Cobb	4	solid		0.15	1.00			5,067,731			4,901,417			5,014,409			5,168,580
Consumers Energy	Cobb	5	solid		0.15	1.00			5,133,332			5,748,538			5,462,145			5,388,204
Consumers Energy	Karn	1	solid		0.15	1.00			7,939,290			8,153,810			7,318,814			9,020,947
Consumers Energy	Karn	2	solid		0.15	1.00			8,784,336			8,192,913			8,530,178			8,706,408
Consumers Energy	Karn	3	dual		0.15	0.40		0.48	5,430,089	2,602,501	0.49	5,170,520	2,540,792	0.55	2,218,160	1,212,244	0.57	1,855,805
Consumers Energy	Karn	4	dual		0.15	0.40		0.48	4,881,440	2,326,589	0.50	2,936,278	1,476,536	0.54	1,434,765	776,276	0.58	925,404
Consumers Energy	Thetford CT	1	gas		0.15	0.40			16,419			8,057			5,286			5,097
Consumers Energy	Thetford CT	2	gas		0.15	0.40			13,187			7,135			5,138			9,062
Consumers Energy	Thetford CT	3	gas		0.15	0.40			11,900			8,192			3,289			5,884
Consumers Energy	Thetford CT	4	gas		0.15	0.40			5,791			7,160			3,384			5,318
Consumers Energy	Weadock	7	solid		0.15	1.00			4,348,739			5,018,497			5,452,648			2,116,732
Consumers Energy	Weadock	8	solid		0.15	1.00			6,069,066			5,199,624			5,008,404			4,898,151
Consumers Energy	Whiting	1	solid		0.15	1.00			3,599,715			3,822,763			3,869,579			3,325,270
Consumers Energy	Whiting	2	solid		0.15	1.00			3,813,878			3,541,774			3,159,438			3,340,050
Consumers Energy	Whiting	3	solid		0.15	1.00			3,546,075			4,574,997			4,238,361			4,422,438
Covert Generating LLC	Covert	1	gas	**0.009**	0.15	0.40	**0.03**		0			0			371,134			273,364
Covert Generating LLC	Covert	2	gas	**0.009**	0.15	0.40	**0.03**		0			0			1,005,724			326,686
Covert Generating LLC	Covert	3	gas	**0.009**	0.15	0.40	**0.03**		0			0			0			732,023
Dearborn Ind. Gen.	Dearborn Ind.	B1	gas	**0.1**	0.15	0.40	**0.08**		593,471			937,146			856,681			1,079,255
Dearborn Ind. Gen.	Dearborn Ind.	B2	gas	**0.1**	0.15	0.40	**0.08**		546,149			795,476			750,113			989,029
Dearborn Ind. Gen.	Dearborn Ind.	B3	gas	**0.1**	0.15	0.40	**0.08**		400,740			967,910			627,718			1,061,786
Dearborn Ind. Gen.	Dearborn Ind.	GTP1	gas	**0.033**	0.15	0.40	**0.05**		381,690			541,442			62,856			187,512
Detroit Edison	Belle River	1	solid		0.15	1.00			21,092,846			23,555,397			20,612,325			18,214,949
Detroit Edison	Belle River	2	solid		0.15	1.00			20,908,556			17,421,262			18,978,701			19,781,320
Detroit Edison	Belle River	CTG121	gas	**0.033**	0.15	0.40	**0.05**		324,049			468,998			172,368			97,269
Detroit Edison	Belle River	CTG122	gas	**0.033**	0.15	0.40	**0.05**		281,535			413,928			133,262			78,801
Detroit Edison	Belle River	CTG131	gas	**0.033**	0.15	0.40	**0.05**		271,184			233,234			149,075			62,515
Detroit Edison	Connors Creek	15	gas		0.15	0.40			264,972			246,262			102,378			146,271
Detroit Edison	Connors Creek	16	gas		0.15	0.40			276,197			207,173			74,398			104,645
Detroit Edison	Connors Creek	17	gas		0.15	0.40			236,651			146,908			99,776			142,950
Detroit Edison	Connors Creek	18	gas		0.15	0.40			265,491			188,754			83,168			131,750
Detroit Edison	Delray	CTG111	gas	**0.055**	0.15	0.40	**0.06**		147,755			285,147			101,493			81,174
Detroit Edison	Delray	CTG121	gas	**0.055**	0.15	0.40	**0.06**		143,171			270,643			84,738			100,543
Detroit Edison	East China	1	gas	**0.036**	0.15	0.40	**0.05**		0			45,663			90,022			0
Detroit Edison	East China	2	gas	**0.036**	0.15	0.40	**0.05**		0			45,653			93,866			0
Detroit Edison	East China	3	gas	**0.036**	0.15	0.40	**0.05**		0			45,266			91,329			0
Detroit Edison	East China	4	gas	**0.036**	0.15	0.40	**0.05**		0			42,601			92,771			0
Detroit Edison	Greenwood	1	dual		0.15	0.40		0.46	4,353,727	2,007,664	0.48	5,891,835	2,851,036	0.49	2,941,199	1,435,819	0.53	2,850,058
Detroit Edison	Greenwood	CTG111	gas	**0.033**	0.15	0.40	**0.05**		247,443			303,921			102,717			17,393
Detroit Edison	Greenwood	CTG112	gas	**0.033**	0.15	0.40	**0.05**		229,920			340,061			72,515			17,865
Detroit Edison	Greenwood	CTG121	gas	**0.033**	0.15	0.40	**0.05**		208,006			307,478			82,515			15,640
Detroit Edison	Hancock	12-1 (5)	gas		0.15	0.40			36,296			11,731			13,584			6,585
Detroit Edison	Hancock	12-2 (6)	gas		0.15	0.40			32,774			14,880			13,984			6,108
Detroit Edison	Harbor Beach	1	solid		0.15	1.00			908,138			1,409,137			930,856			908,046
Detroit Edison	Marysville	9	solid		0.15	1.00			233,240			0			0			0

	Source information		Operations Data								Ozone Season Values							
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-14**	**Fuel Adj Factor**	**Arith. Ave.**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**
Detroit Edison	Marysville	10	solid		0.15	1.00			193,046			0			0			0
Detroit Edison	Marysville	11	solid		0.15	1.00			260,964			0			0			0
Detroit Edison	Marysville	12	solid		0.15	1.00			258,445			0			0			0
Detroit Edison	Monroe	1	solid		0.15	1.00			17,494,384			18,596,466			15,073,173			16,557,060
Detroit Edison	Monroe	2	solid		0.15	1.00			16,690,339			18,828,555			14,858,228			15,715,116
Detroit Edison	Monroe	3	solid		0.15	1.00			21,489,324			15,733,177			16,431,859			12,806,092
Detroit Edison	Monroe	4	solid		0.15	1.00			20,854,415			16,089,941			25,444,852			19,562,301
Detroit Edison	River Rouge	1	gas		0.15	0.40			734,911			549,025			252,639			18,092
Detroit Edison	River Rouge	2	solid		0.15	1.00			4,422,619			7,791,035			6,867,920			6,828,431
Detroit Edison	River Rouge	3	solid		0.15	1.00			7,918,497			7,204,611			5,297,685			6,940,095
Detroit Edison	St. Clair	1	solid		0.15	1.00			3,402,797			3,787,656			2,847,462			3,940,939
Detroit Edison	St. Clair	2	solid		0.15	1.00			4,445,613			3,033,858			2,274,844			4,163,962
Detroit Edison	St. Clair	3	solid		0.15	1.00			3,022,297			4,556,164			3,914,288			3,486,917
Detroit Edison	St. Clair	4	solid		0.15	1.00			3,790,539			4,082,900			3,640,161			3,524,985
Detroit Edison	St. Clair	6	solid		0.15	1.00			8,240,084			7,764,080			7,777,085			7,669,330
Detroit Edison	St. Clair	7	solid		0.15	1.00			7,368,393			11,284,581			10,049,199			11,355,886
Detroit Edison	Trenton Channel	16	solid		0.15	1.00			1,622,536			1,587,597			1,633,487			2,106,205
Detroit Edison	Trenton Channel	17	solid		0.15	1.00			1,814,026			1,617,612			1,724,274			1,962,086
Detroit Edison	Trenton Channel	18	solid		0.15	1.00			1,812,309			1,691,132			1,370,815			1,974,104
Detroit Edison	Trenton Channel	19	solid		0.15	1.00			1,992,713			1,682,477			1,565,822			1,871,634
Detroit Edison	Trenton Channel	9A	solid		0.15	1.00			11,376,671			12,886,689			12,551,960			11,544,193
Detroit PLD	Mistersky	5	gas		0.15	0.40			598,881			1,661,025			1,276,430			1,597,254
Detroit PLD	Mistersky	6	gas		0.15	0.40			1,794,436			0			0			0
Detroit PLD	Mistersky	7	gas		0.15	0.40			2,392,548			1,049,466			1,060,243			810,625
Detroit PLD	Mistersky	GT-1	liquid		0.15	0.60			0			0			102,216			10,522
Dynegy	Renaissance	CT1	gas	**0.055**	0.15	0.40	**0.06**		0			731,088			242,131			539,088
Dynegy	Renaissance	CT2	gas	**0.055**	0.15	0.40	**0.06**		0			630,495			248,336			60,351
Dynegy	Renaissance	CT3	gas	**0.055**	0.15	0.40	**0.06**		0			0			231,850			89,086
Dynegy	Renaissance	CT4	gas	**0.055**	0.15	0.40	**0.06**		0			589,651			200,584			90,756
FirstEnergy Genco	Sumpter	1	gas		0.15	0.40			0			406,060			150,452			38,905
FirstEnergy Genco	Sumpter	2	gas		0.15	0.40			0			347,284			161,778			42,030
FirstEnergy Genco	Sumpter	3	gas		0.15	0.40			0			353,473			155,869			38,631
FirstEnergy Genco	Sumpter	4	gas		0.15	0.40			0			392,267			119,315			48,182
Grand Haven BLP	Sims	3	solid		0.15	1.00			1,913,831			1,298,809			1,523,167			1,454,537
Holland BPW	48th Street	7	gas		0.15	0.40			124,516			235,579			41,111			72,527
Holland BPW	48th Street	8	gas		0.15	0.40			44,613			89,537			52,342			5,338
Holland BPW	48th Street	9	gas	**0.081**	0.15	0.40	**0.07**		358,387			591,954			199,981			122,340
Holland BPW	De Young	5	solid		0.15	1.00			948,165			803,750			938,115			792,040
Kinder Morgan	Jackson Power	7EA	gas	**0.033**	0.15	0.40	**0.05**		0			908,903			227,749			73,992
Kinder Morgan	Jackson Power	LM1	gas	**0.081**	0.15	0.40	**0.07**		0			407,843			91,180			40,383
Kinder Morgan	Jackson Power	LM2	gas	**0.081**	0.15	0.40	**0.07**		0			385,944			86,062			38,188
Kinder Morgan	Jackson Power	LM3	gas	**0.081**	0.15	0.40	**0.07**		0			237,704			85,070			24,192
Kinder Morgan	Jackson Power	LM4	gas	**0.081**	0.15	0.40	**0.07**		0			387,859			81,548			41,628
Kinder Morgan	Jackson Power	LM5	gas	**0.081**	0.15	0.40	**0.07**		0			388,691			86,957			33,267
Kinder Morgan	Jackson Power	LM6	gas	**0.081**	0.15	0.40	**0.07**		0			365,514			85,492			27,699
Lansing BWL	Eckert Station	1	solid		0.15	1.00			1,176,193			1,026,237			1,102,483			821,432
Lansing BWL	Eckert Station	2	solid		0.15	1.00			1,185,395			1,074,194			846,646			1,111,663
Lansing BWL	Eckert Station	3	solid		0.15	1.00			964,397			1,287,915			993,046			1,279,568
Lansing BWL	Eckert Station	4	solid		0.15	1.00			2,367,356			2,385,076			2,203,249			2,077,331
Lansing BWL	Eckert Station	5	solid		0.15	1.00			2,165,973			1,849,618			2,013,729			1,831,203
Lansing BWL	Eckert Station	6	solid		0.15	1.00			2,032,492			2,096,183			2,337,225			2,054,909
Lansing BWL	Erickson	1	solid		0.15	1.00			3,693,555			4,577,260			4,400,621			5,261,478
Marquette. City of	Shiras	3	solid		0.15	1.00			1,518,405			1,551,934			1,561,098			1,436,504
Michigan Power LP	MI Power LP	G101	gas	**0.05**	0.15	0.40	**0.06**		3,234,374			3,958,110			4,195,664			4,226,229
Michigan Public Pwr	Kalkaska CT #1	1A	gas	**0.092**	0.15	0.40	**0.08**		0			0			37,050			25,061
Michigan Public Pwr	Kalkaska CT #1	1B	gas	**0.092**	0.15	0.40	**0.08**		0			0			43,174			16,173
Midland Cogen V.	Midland Cogen V.	GT10	gas	**0.149**	0.15	0.40	**0.10**		2,835,697			2,942,063			1,846,749			3,316,802
Midland Cogen V.	Midland Cogen V.	GT11	gas	**0.149**	0.15	0.40	**0.10**		2,946,020			2,780,781			2,357,288			3,469,205
Midland Cogen V.	Midland Cogen V.	GT12	gas	**0.1**	0.15	0.40	**0.08**		2,967,937			2,590,448			2,208,821			2,873,082
Midland Cogen V.	Midland Cogen V.	GT13	gas	**0.149**	0.15	0.40	**0.10**		3,429,136			2,602,609			2,402,116			3,449,706
Midland Cogen V.	Midland Cogen V.	GT14	gas	**0.149**	0.15	0.40	**0.10**		2,785,723			2,769,489			2,051,354			3,430,409

	Source information		Operations Data									Ozone Season Values						
Company Name	**Plant Name**	**Unit ID**	**Fuel Type**	**Permit Limit (if applicable)**	**Emission Factor 2010-14**	**Fuel Adj Factor**	**Arith. Ave.**	**2001 Fuel Ratio**	**2001 Heat Input**	**2001 Adjusted Heat Input**	**2002 Fuel Ratio**	**2002 Heat Input**	**2002 Adjusted Heat Input**	**2003 Fuel Ratio**	**2003 Heat Input**	**2003 Adjusted Heat Input**	**2004 Fuel Ratio**	**2004 Heat Input**
Midland Cogen V.	Midland Cogen V.	GT3	gas	**0.149**	0.15	0.40	**0.10**		2,846,179			2,796,031			2,452,390			3,450,372
Midland Cogen V.	Midland Cogen V.	GT4	gas	**0.149**	0.15	0.40	**0.10**		2,844,802			2,617,087			2,005,539			3,076,638
Midland Cogen V.	Midland Cogen V.	GT5	gas	**0.149**	0.15	0.40	**0.10**		3,123,470			2,428,780			2,238,596			3,468,621
Midland Cogen V.	Midland Cogen V.	GT6	gas	**0.149**	0.15	0.40	**0.10**		2,662,165			2,817,748			2,302,016			2,802,132
Midland Cogen V.	Midland Cogen V.	GT7	gas	**0.149**	0.15	0.40	**0.10**		2,702,821			2,522,885			2,085,772			3,343,686
Midland Cogen V.	Midland Cogen V.	GT8	gas	**0.149**	0.15	0.40	**0.10**		3,415,266			2,714,763			1,907,860			3,386,642
Midland Cogen V.	Midland Cogen V.	GT9	gas	**0.149**	0.15	0.40	**0.10**		2,914,151			2,734,935			2,402,622			3,326,102
Mirant Zeeland	Zeeland Power	1	gas	**0.04**	0.15	0.40	**0.05**		526,271			429,514			86,239			0
Mirant Zeeland	Zeeland Power	2	gas	**0.04**	0.15	0.40	**0.05**		563,173			438,410			106,859			32,508
Mirant Zeeland	Zeeland Power	3	gas	**0.013**	0.15	0.40	**0.04**		0			1,059,959			635,189			746,197
Mirant Zeeland	Zeeland Power	4	gas	**0.013**	0.15	0.40	**0.04**		0			975,450			569,187			525,717
MSCPA	Enidcott Gen St	1	solid		0.15	1.00			2,138,461			2,370,990			2,434,400			2,393,181
WE Energies	Presque Isle	2	solid		0.15	1.00			232,161			47,268			23,213			283,672
WE Energies	Presque Isle	3	solid		0.15	1.00			1,296,693			1,625,166			872,400			1,495,516
WE Energies	Presque Isle	4	solid		0.15	1.00			1,612,406			1,000,893			1,462,741			1,526,912
WE Energies	Presque Isle	5	solid		0.15	1.00			2,603,708			2,697,695			2,061,455			2,230,869
WE Energies	Presque Isle	6	solid		0.15	1.00			2,400,204			1,883,125			1,747,689			2,422,967
WE Energies	Presque Isle	7	solid		0.15	1.00			2,793,953			3,041,844			2,304,342			2,933,879
WE Energies	Presque Isle	8	solid		0.15	1.00			2,887,178			2,849,343			2,735,688			3,033,454
WE Energies	Presque Isle	9	solid		0.15	1.00			2,785,068			2,868,513			2,270,262			2,721,706
Wyandotte DMS	Wyandotte	5	gas		0.150	0.40			8,198			132,486			0			0
Wyandotte DMS	Wyandotte	7	solid		0.15	1.00			1,171,251			873,374			1,045,593			1,053,653
Wyandotte DMS	Wyandotte	8	solid		0.150	1.00			759,822			612,706			564,754			758,939

Corrections to the numbers: rounding up if >0.5

	Source information						Calculations				
Company Name	**Plant Name**	**Unit ID**	**2004 Adjusted Heat Input**	**2005 Fuel Ratio**	**2005 Heat Input**	**2005 Adjusted Heat Input**	**Highest 2 year ave**	**Calculated CAIR**	**Adjusted CAIR**	**CAIR Ozone Allowed 2010**	**CAIR Ozone Allowed 2011**
Cadillac RE	Cadillac Renew	GEN1			1517985		1,542,690	116	111	**111**	**111**
CMS Gen/MI Pwr	Kalamazoo River	1			164,296		110,856	4	4	**4**	**4**
CMS Gen/MI Pwr	Livingston Station	001			89,307		62,745	2	2	**2**	**2**
CMS Gen/MI Pwr	Livingston Station	002			91,409		62,862	2	2	**2**	**2**
CMS Gen/MI Pwr	Livingston Station	003			108,419		70,891	2	2	**2**	**2**
CMS Gen/MI Pwr	Livingston Station	004			91,425		63,189	2	2	**2**	**2**
CMS Generation	Genesee Power	GEN1			1,708,417		1,591,821	119	115	**115**	**115**
CMS Generation	Grayling Station	GEN1			1,477,159		1,591,294	119	115	**115**	**115**
CMS Generation	TES Filer City	B1			1,170,467		1,354,229	102	98	**98**	**98**
CMS Generation	TES Filer City	B2			1,170,467		1,354,229	102	98	**98**	**98**
Consumers Energy	Campbell	1			8,818,479		9,460,334	710	682	**682**	**682**
Consumers Energy	Campbell	2			10,363,932		10,575,193	793	763	**763**	**763**
Consumers Energy	Campbell	3			24,446,249		26,990,557	2,024	1,947	**1,947**	**1,947**
Consumers Energy	Cobb	1			241,779		240,064	7	7	**7**	**7**
Consumers Energy	Cobb	2			231,899		225,508	7	7	**7**	**7**
Consumers Energy	Cobb	3			209,770		239,493	7	7	**7**	**7**
Consumers Energy	Cobb	4			4,737,228		5,118,156	384	369	**369**	**369**
Consumers Energy	Cobb	5			5,645,708		5,697,123	427	411	**411**	**411**
Consumers Energy	Karn	1			8,989,897		9,005,422	675	650	**650**	**650**
Consumers Energy	Karn	2			8,155,171		8,745,372	656	631	**631**	**631**
Consumers Energy	Karn	3	1,048,566	0.49	3,299,963	1,604,519	2,571,647	193	185	**185**	**185**
Consumers Energy	Karn	4	532,547	0.48	3,052,861	1,469,948	1,901,562	143	137	**137**	**137**
Consumers Energy	Thetford CT	1			67,514		41,967	1	1	**1**	**1**
Consumers Energy	Thetford CT	2			76,391		44,789	1	1	**1**	**1**
Consumers Energy	Thetford CT	3			81,011		46,456	1	1	**1**	**1**
Consumers Energy	Thetford CT	4			85,354		46,257	1	1	**1**	**1**
Consumers Energy	Weadock	7			4,908,421		5,235,573	393	378	**378**	**378**
Consumers Energy	Weadock	8			4,604,029		5,634,345	423	406	**406**	**406**
Consumers Energy	Whiting	1			3,687,576		3,846,171	288	277	**277**	**277**
Consumers Energy	Whiting	2			3,822,454		3,818,166	286	275	**275**	**275**
Consumers Energy	Whiting	3			3,421,845		4,498,718	337	324	**324**	**324**
Covert Generating LLC	Covert	1			1,868,854		1,119,994	19	19	**19**	**19**
Covert Generating LLC	Covert	2			2,113,179		1,559,452	27	26	**26**	**26**
Covert Generating LLC	Covert	3			1,977,411		1,354,717	23	22	**23**	**23**
Dearborn Ind. Gen.	Dearborn Ind.	B1			1,937,257		1,508,256	60	58	**58**	**58**
Dearborn Ind. Gen.	Dearborn Ind.	B2			2,017,352		1,503,191	60	58	**58**	**58**
Dearborn Ind. Gen.	Dearborn Ind.	B3			1,903,475		1,482,631	59	57	**57**	**57**
Dearborn Ind. Gen.	Dearborn Ind.	GTP1			1,428,166		984,804	23	22	**22**	**22**
Detroit Edison	Belle River	1			18,538,480		22,324,122	1,674	1,610	**1,610**	**1,610**
Detroit Edison	Belle River	2			19,900,880		20,404,718	1,530	1,472	**1,472**	**1,472**
Detroit Edison	Belle River	CTG121			430,834		449,916	10	10	**10**	**10**
Detroit Edison	Belle River	CTG122			431,154		422,541	10	9	**9**	**9**
Detroit Edison	Belle River	CTG131			422,589		346,887	8	8	**8**	**8**
Detroit Edison	Connors Creek	15			371,020		317,996	10	9	**9**	**9**
Detroit Edison	Connors Creek	16			317,496		296,847	9	9	**9**	**9**
Detroit Edison	Connors Creek	17			277,818		257,235	8	7	**7**	**7**
Detroit Edison	Connors Creek	18			319,128		292,310	9	8	**8**	**8**
Detroit Edison	Delray	CTG111			175,399		230,273	7	6	**6**	**6**
Detroit Edison	Delray	CTG121			269,442		270,043	8	7	**7**	**7**
Detroit Edison	East China	1			265,055		177,539	4	4	**4**	**4**
Detroit Edison	East China	2			271,955		182,911	4	4	**4**	**4**
Detroit Edison	East China	3			271,717		181,523	4	4	**4**	**4**
Detroit Edison	East China	4			247,276		170,024	4	4	**4**	**4**
Detroit Edison	Greenwood	1	1,517,902	0.48	5,413,305	2,619,477	2,735,256	205	197	**197**	**197**
Detroit Edison	Greenwood	CTG111			458,781		381,351	9	9	**9**	**9**
Detroit Edison	Greenwood	CTG112			458,718		399,390	9	9	**9**	**9**
Detroit Edison	Greenwood	CTG121			175,347		257,742	6	6	**6**	**6**
Detroit Edison	Hancock	12-1 (5)			19,770		28,033	1	1	**1**	**1**
Detroit Edison	Hancock	12-2 (6)			6,185		23,827	1	1	**1**	**1**
Detroit Edison	Harbor Beach	1			1,588,783		1,498,960	112	108	**108**	**108**
Detroit Edison	Marysville	9			0		116,620	9	8	**8**	**8**

Source information							Calculations				
Company Name	Plant Name	Unit ID	2004 Adjusted Heat Input	2005 Fuel Ratio	2005 Heat Input	2005 Adjusted Heat Input	Highest 2 year ave	Calculated CAIR	Adjusted CAIR	CAIR Ozone Allowed 2010	CAIR Ozone Allowed 2011
Detroit Edison	Marysville	10			0		96,523	7	7	**7**	**7**
Detroit Edison	Marysville	11			0		130,482	10	9	**9**	**9**
Detroit Edison	Marysville	12			0		129,223	10	9	**9**	**9**
Detroit Edison	Monroe	1			18,389,509		18,492,988	1,387	1,334	**1,334**	**1,334**
Detroit Edison	Monroe	2			19,300,902		19,064,729	1,430	1,375	**1,375**	**1,375**
Detroit Edison	Monroe	3			20,834,665		21,161,995	1,587	1,526	**1,526**	**1,526**
Detroit Edison	Monroe	4			21,031,547		23,238,200	1,743	1,676	**1,676**	**1,676**
Detroit Edison	River Rouge	1			55,402		641,968	19	19	**19**	**19**
Detroit Edison	River Rouge	2			6,211,562		7,329,478	550	529	**529**	**529**
Detroit Edison	River Rouge	3			5,617,052		7,561,554	567	545	**545**	**545**
Detroit Edison	St. Clair	1			3,658,570		3,864,298	290	279	**279**	**279**
Detroit Edison	St. Clair	2			3,477,329		4,304,788	323	310	**310**	**310**
Detroit Edison	St. Clair	3			3,514,244		4,235,226	318	305	**305**	**305**
Detroit Edison	St. Clair	4			3,832,335		3,957,618	297	285	**285**	**285**
Detroit Edison	St. Clair	6			7,174,177		8,008,585	601	578	**578**	**578**
Detroit Edison	St. Clair	7			9,087,177		11,320,234	849	816	**816**	**816**
Detroit Edison	Trenton Channel	16			1,696,304		1,901,255	143	137	**137**	**137**
Detroit Edison	Trenton Channel	17			1,634,175		1,888,056	142	136	**136**	**136**
Detroit Edison	Trenton Channel	18			1,636,050		1,893,207	142	137	**137**	**137**
Detroit Edison	Trenton Channel	19			1,642,589		1,932,174	145	139	**139**	**139**
Detroit Edison	Trenton Channel	9A			12,221,984		12,719,325	954	917	**917**	**917**
Detroit PLD	Mistersky	5			981,641		1,629,140	49	47	**47**	**47**
Detroit PLD	Mistersky	6			759,654		1,277,045	38	37	**37**	**37**
Detroit PLD	Mistersky	7			1,001,238		1,726,396	52	50	**50**	**50**
Detroit PLD	Mistersky	GT-1			27,442		64,829	3	3	**3**	**3**
Dynegy	Renaissance	CT1			874,373		802,731	23	22	**22**	**22**
Dynegy	Renaissance	CT2			637,468		633,982	18	18	**18**	**18**
Dynegy	Renaissance	CT3			1,049,165		640,508	18	18	**18**	**18**
Dynegy	Renaissance	CT4			1,115,844		852,748	25	24	**24**	**24**
FirstEnergy Genco	Sumpter	1			293,630		349,845	10	10	**10**	**10**
FirstEnergy Genco	Sumpter	2			295,387		321,336	10	9	**9**	**9**
FirstEnergy Genco	Sumpter	3			285,696		319,585	10	9	**9**	**9**
FirstEnergy Genco	Sumpter	4			285,632		338,950	10	10	**10**	**10**
Grand Haven BLP	Sims	3			2,123,814		2,018,823	151	146	**146**	**146**
Holland BPW	48th Street	7			21,126		180,048	5	5	**5**	**5**
Holland BPW	48th Street	8			33,238		70,940	2	2	**2**	**2**
Holland BPW	48th Street	9			80,517		475,171	17	16	**16**	**16**
Holland BPW	De Young	5			854,060		943,140	71	68	**68**	**68**
Kinder Morgan	Jackson Power	7EA			624,055		766,479	18	17	**17**	**17**
Kinder Morgan	Jackson Power	LM1			165,200		286,522	10	10	**10**	**10**
Kinder Morgan	Jackson Power	LM2			178,236		282,090	10	10	**10**	**10**
Kinder Morgan	Jackson Power	LM3			239,320		238,512	8	8	**8**	**8**
Kinder Morgan	Jackson Power	LM4			168,090		277,975	10	9	**9**	**9**
Kinder Morgan	Jackson Power	LM5			241,329		315,010	11	11	**11**	**11**
Kinder Morgan	Jackson Power	LM6			184,457		274,986	10	9	**9**	**9**
Lansing BWL	Eckert Station	1			1,075,204		1,139,338	85	82	**82**	**82**
Lansing BWL	Eckert Station	2			1,076,943		1,148,529	86	83	**83**	**83**
Lansing BWL	Eckert Station	3			1,157,985		1,283,742	96	93	**93**	**93**
Lansing BWL	Eckert Station	4			1,665,282		2,376,216	178	171	**171**	**171**
Lansing BWL	Eckert Station	5			1,940,193		2,089,851	157	151	**151**	**151**
Lansing BWL	Eckert Station	6			2,186,765		2,261,995	170	163	**163**	**163**
Lansing BWL	Erickson	1			4,638,331		4,949,905	371	357	**357**	**357**
Marquette. City of	Shiras	3			1,548,393		1,556,516	117	112	**112**	**112**
Michigan Power LP	MI Power LP	G101			4,160,198		4,210,947	116	111	**111**	**111**
Michigan Public Pwr	Kalkaska CT #1	1A			16,314		31,056	1	1	**2**	**2**
Michigan Public Pwr	Kalkaska CT #1	1B			23,548		33,361	1	1	**2**	**2**
Midland Cogen V.	Midland Cogen V.	GT10			1,129,042		3,129,433	164	157	**157**	**157**
Midland Cogen V.	Midland Cogen V.	GT11			1,023,090		3,207,613	168	161	**161**	**161**
Midland Cogen V.	Midland Cogen V.	GT12			837,169		2,920,510	117	112	**112**	**112**
Midland Cogen V.	Midland Cogen V.	GT13			1,992,625		3,439,421	180	173	**173**	**173**
Midland Cogen V.	Midland Cogen V.	GT14			2,934,540		3,182,475	166	160	**160**	**160**

Source information							Calculations				
Company Name	**Plant Name**	**Unit ID**	**2004 Adjusted Heat Input**	**2005 Fuel Ratio**	**2005 Heat Input**	**2005 Adjusted Heat Input**	**Highest 2 year ave**	**Calculated CAIR**	**Adjusted CAIR**	**CAIR Ozone Allowed 2010**	**CAIR Ozone Allowed 2011**
Midland Cogen V.	Midland Cogen V.	GT3			3,132,745		3,291,559	172	165	**165**	**165**
Midland Cogen V.	Midland Cogen V.	GT4			2,869,075		2,972,857	155	149	**149**	**149**
Midland Cogen V.	Midland Cogen V.	GT5			3,205,444		3,337,033	174	168	**168**	**168**
Midland Cogen V.	Midland Cogen V.	GT6			3,273,214		3,045,481	159	153	**153**	**153**
Midland Cogen V.	Midland Cogen V.	GT7			1,195,738		3,023,254	158	152	**152**	**152**
Midland Cogen V.	Midland Cogen V.	GT8			1,236,445		3,400,954	178	171	**171**	**171**
Midland Cogen V.	Midland Cogen V.	GT9			1,091,027		3,120,127	163	157	**157**	**157**
Mirant Zeeland	Zeeland Power	1			277,935		477,893	12	11	**11**	**11**
Mirant Zeeland	Zeeland Power	2			140,803		500,792	13	12	**12**	**12**
Mirant Zeeland	Zeeland Power	3			1,486,233		1,273,096	23	22	**22**	**22**
Mirant Zeeland	Zeeland Power	4			1,625,357		1,300,404	24	23	**23**	**23**
MSCPA	Enidcott Gen St	1			2,939,389		2,686,895	202	194	**194**	**194**
WE Energies	Presque Isle	2			424,944		354,308	27	26	**26**	**26**
WE Energies	Presque Isle	3			2,072,168		1,848,667	139	133	**133**	**133**
WE Energies	Presque Isle	4			1,688,378		1,650,392	124	119	**119**	**119**
WE Energies	Presque Isle	5			2,442,717		2,650,702	199	191	**191**	**191**
WE Energies	Presque Isle	6			2,303,735		2,411,586	181	174	**174**	**174**
WE Energies	Presque Isle	7			3,203,683		3,122,764	234	225	**225**	**225**
WE Energies	Presque Isle	8			2,706,456		2,960,316	222	214	**214**	**214**
WE Energies	Presque Isle	9			2,798,186		2,833,350	213	204	**204**	**204**
Wyandotte DMS	Wyandotte	5			0		70,342	2	2	**2**	**2**
Wyandotte DMS	Wyandotte	7			1,231,637		1,201,444	90	87	**87**	**87**
Wyandotte DMS	Wyandotte	8			920,942		840,382	63	61	**61**	**61**
Corrections to the numbers: rounding up if >0.5								**29,451**	**28,321**	**28,321**	**28,321**

Annual Hardship Request

Hardship Budget: 1,200

Company	Plant Name	Boiler ID	ACTUALS MI Original allocations (tons)	Hard Ship Request (tons)	**2009 Adjusted Hardships Allowed**	**2010 Adjusted Hardships Allowed**	**2011 Adjusted Hardships Allowed**	MDEQ Calculations Ave Heat Input MMBTu	Predicted Nox Emission Rate	Calc Needed Allocations (tons)	Current CAIR Allocations (tons)	Prelim Hardships Calc (tons)	Adjusted Hardships Allowed (tons)	Corrected Hardship Values rounding
Detroit PLD	Mistersky	5	100	192	**88**	**88**	**88**	3,563,411	0.168	299	100	199	88	88
Detroit PLD	Mistersky	6	77	170	**77**	**77**	**77**	2,716,602	0.185	251	77	174	77	77
Detroit PLD	Mistersky	7	114	194	**89**	**89**	**89**	4,039,069	0.156	315	114	201	89	89
Detroit PLD	Mistersky	GT-1	5	26	**12**	**12**	**12**	107,856	0.580	31	5	26	12	12
Grand Haven BLP	Sims	3	315	259	**118**	**118**	**118**	4,470,734	0.260	581	315	266	118	118
Holland BPW	De Young	5	163	278	**126**	**126**	**126**	2,307,180	0.388	448	163	285	126	126
Lansing BWL	Eckert Station	1	190	65	**34**	**34**	**34**	2,702,758	0.197	266	190	76	34	34
Lansing BWL	Eckert Station	2	191	120	**61**	**61**	**61**	2,703,802	0.243	329	191	138	61	61
Lansing BWL	Eckert Station	3	210	42	**22**	**22**	**22**	2,980,297	0.175	261	210	51	22	22
Lansing BWL	Eckert Station	4	388	155	**75**	**75**	**75**	5,498,473	0.203	558	388	170	75	75
Lansing BWL	Eckert Station	5	366	157	**79**	**79**	**79**	5,195,875	0.210	546	366	180	79	79
Lansing BWL	Eckert Station	6	364	143	**72**	**72**	**72**	5,165,255	0.204	527	364	163	72	72
Lansing BWL	Erickson	1	769	251	**142**	**142**	**142**	10,912,871	0.200	1,091	769	322	143	142
Marquette. City of	Shiras	3	271	22	**15**	**15**	**15**	3,845,310	0.158	304	271	33	15	15
MSCPA	Enidcott Gen St	1	415	141	**51**	**51**	**51**	5,884,551	0.180	530	415	115	51	51
Wyandotte DMS	Wyandotte	7	187	294	**131**	**131**	**131**	2,657,771	0.362	481	187	294	130	131
Wyandotte DMS	Wyandotte	8	122	29	**8**	**8**	**8**	1,736,679	0.162	141	122	19	8	8
	TOTALS			**2,538**	**1,200**	**1,200**	**1,200**					**2,711**	**1,200**	**1,200**

Ozone Hardship Request

Hardship Budget: 650			ACTUALS w/rounding corrections				MDEQ Calculations						
Company	Plant Name	Boiler ID	MI Original allocations (tons)	Hard Ship Request (tons)	**2010 Adjusted Hardships Allowed**	**2011 Adjusted Hardships Allowed**	Ave Heat Input MMBTu	Predicted Nox Emission Rate	Calc Needed Allocations (tons)	Current CAIR Allocations (tons)	Prelim Hardships Calc (tons)	Adjusted Hardships Allowed (tons)	Corrected Hardship Values rounding
Detroit PLD	Mistersky	5	47	88	**50**	**50**	1,629,140	0.168	137	47	90	51	50
Detroit PLD	Mistersky	6	37	80	**46**	**46**	1,277,045	0.185	118	37	81	46	46
Detroit PLD	Mistersky	7	50	83	**47**	**47**	1,726,396	0.156	135	50	85	48	47
Detroit PLD	Mistersky	GT-1	3	16	**9**	**9**	64,829	0.580	19	3	16	9	9
Grand Haven BLP	Sims	3	146	70	**66**	**66**	2,018,823	0.260	262	146	116	66	66
Holland BPW	De Young	5	68	113	**65**	**65**	943,140	0.388	183	68	115	65	65
Lansing BWL	Eckert Station	1	82	27	**17**	**17**	1,139,338	0.197	112	82	30	17	17
Lansing BWL	Eckert Station	2	83	54	**32**	**32**	1,148,529	0.243	140	83	57	32	32
Lansing BWL	Eckert Station	3	93	16	**11**	**11**	1,283,742	0.175	112	93	19	11	11
Lansing BWL	Eckert Station	4	171	63	**40**	**40**	2,376,216	0.203	241	171	70	40	40
Lansing BWL	Eckert Station	5	151	63	**39**	**39**	2,089,851	0.210	219	151	68	39	39
Lansing BWL	Eckert Station	6	163	61	**38**	**38**	2,261,995	0.204	231	163	68	38	38
Lansing BWL	Erickson	1	357	124	**77**	**77**	4,949,905	0.200	495	357	138	78	77
Marquette. City of	Shiras	3	112	13	**8**	**8**	1,556,516	0.161	125	112	13	8	8
MSCPA	Enidcott Gen St	1	194	61	**27**	**27**	2,686,895	0.180	242	194	48	27	27
Michigan State University	Simon	0053	126	70	**0**	**0**	737,281	0.250	92	126	0	0	0
Michigan State University	Simon	0054	101	59	**0**	**0**	595,058	0.260	77	101	0	0	0
Michigan State University	Simon	0055	147	112	**0**	**0**	862,482	0.270	116	147	0	0	0
Michigan State University	Simon	0056	154	0	**0**	**0**	907,335	0.140	64	154	0	0	0
Wyandotte DMS	Wyandotte	7	87	127	**74**	**74**	1,201,444	0.362	217	87	130	74	74
Wyandotte DMS	Wyandotte	8	61	6	**4**	**4**	840,382	0.162	68	61	7	4	4
	Totals			**1,039**	**650**	**650**					**1,152**	**650**	**650**

Note: MSU's request for hardships was not acceptable for 2010 and 2011.

Company Name	SRN	Unit ID	Name Plate Capacity in mmBtu	County	Emission Factor	2001 Heat Input	2002 Heat Input	2003 Heat Input	2004 Heat Input	2005 Heat Input	Highest 2 year ave.	CAIR Allow	Adjusted CAIR 2010	Corrected (Rounding) CAIR 2010	Corrected (Rounding) CAIR 2011
CE - Karn_Weadock	B2840	A	300	Bay	0.17	61,855	27,750	23,859	24,640	47,738	54,797	5	**9**	**9**	**9**
CE - Karn_Weadock	B2840	B	300	Bay	0.17	77,086	54,657	20,570	29,235	60,886	68,986	6	**12**	**12**	**12**
Dearborn Ind. Gen.	N6631	GT21	1562	Wayne	**0.03**	2,956,150	3,849,500	755,800	1,978,000	1,700,445	3,402,825	56	**112**	**112**	**112**
Dearborn Ind. Gen.	N6631	GT31	1562	Wayne	**0.03**	2,560,600	2,855,100	1,075,300	1,544,800	1,950,156	2,707,850	45	**89**	**89**	**89**
Dow Chemical USA	A4033	0401	300	Midland	0.17	8,100	21,935	4,755	2,728	1,362	15,017	1	**3**	**5**	**5**
Dow Chemical USA	A4033	0402	300	Midland	0.17	7,115	21,626	3,428	3,418	1,357	14,370	1	**2**	**4**	**4**
Graphics Pkg.	B1678	0003	253	Kalamazoo	0.17	753,521	462,844	753,095	642,279	630,034	753,308	64	**128**	**128**	**128**
Lansing BW&L	B2647	0014	290	Ingham	0.17	345,726	20,554	0	0	0	183,140	16	**31**	**31**	**31**
Menasha Corp	A0023	0024	294	Allegan	0.17	511,728	461,675	523,686	514,186	333,643	518,936	44	**88**	**88**	**88**
Menasha Corp	A0023	0025	294	Allegan	0.17	530,507	490,743	534,494	506,831	330,777	532,501	45	**91**	**90**	**90**
MSU	K3249	0053	300	Ingham	0.17	637,673	621,598	599,293	407,107	836,889	737,281	63	**126**	**125**	**125**
MSU	K3249	0054	300	Ingham	0.17	503,492	543,773	532,129	555,702	634,413	595,058	51	**101**	**101**	**101**
MSU	K3249	0055	452	Ingham	0.17	540,050	789,106	699,677	784,297	935,858	862,482	73	**147**	**147**	**147**
MSU	K3249	0056	433	Ingham	0.17	755,606	649,942	1,059,065	713,930	576,236	907,335	77	**154**	**154**	**154**
U of M	M0675	003	315	Washtenaw	0.17	233,845	152,103	141,133	338,819	509,756	424,288	36	**72**	**72**	**72**
U of M	M0675	004	315	Washtenaw	0.17	239,971	168,956	469,248	201,498	516,962	493,105	42	**84**	**84**	**84**
U of M	M0675	006	358	Washtenaw	**0.10**	94,187	508,152	350,087	657,491	130,943	582,822	29	**58**	**58**	**58**
												654	**1,309**	**1,309**	**1,309**