
Wolverine Power Supply Cooperative, Inc.

RESPONSE TO COMMENTS DOCUMENT

June 29, 2011

PERMIT No. 317-07



Rick Snyder, Governor

Air Quality Division Michigan Department of Environmental Quality

INTERNET: <http://www.michigan.gov/air>

G. Vinson Hellwig, Chief
Air Quality Division
Constitution Hall, 3rd Floor
525 West Allegan Street
P.O. Box 30260
Lansing, Michigan 48909-7760
Phone: (517) 373-7023
Fax: (517) 373-1265

Table of Contents

Section	Page
Public Participation Process	3
Summary of Comments Resulting in Changes to the Permit.....	4
Summary of Significant Comments.....	17
A. Alternatives Analysis	17
B. MEPA/Rule 901	22
C. Public Health and Environment Concerns.....	26
1. Comments on Environmental Justice Concerns	41
D. Dispersion Modeling.....	43
E. Maximum Achievable Control Technology (MACT) Review	53
F. Best Available Control Technology (BACT) Review	71
1. IGCC	71
2. Clean Fuels.....	72
3. Opacity.....	80
4. PM2.5.....	80
5. PM10.....	82
6. NOx.....	84
7. SO2.....	87
8. CO/VOC.....	93
9. Greenhouse Gases (GHG)	95
G. Material Handling	114
H. Ancillary Equipment.....	118
I. Control Equipment	120
J. Start-up and Shut-down Emissions.....	121
K. Annual Emissions	122

L. Monitoring	125
M. Compliance Testing	128
N. Enforcement	129
O. Rules and Regulations	131
P. Malfunction Abatement Plan (MAP)	132
Q. Emergencies and Safety Concerns.....	133
R. Public Participation Process.....	134
S. Miscellaneous.....	136
T. Other Comments Received – Not Regulated by the AQD.....	140

I. PUBLIC PARTICIPATION PROCESS

Wolverine Power Supply Cooperative, Inc's (Wolverine) Permit to Install application No. 317-07 is for the proposed installation and operation of a 600 megawatt (MW) (net) solid fuel-fired power plant, which will be located in the existing Carmeuse quarry (formerly Oglebay Norton) property, directly south of Rogers City, Michigan. The public participation process involved providing information for public review including fact sheets, technical summaries, proposed permit terms and conditions; several public comment periods, informational meetings, and public hearings were held; and the receipt of written and verbal public comments on staff's analysis of the application and the proposed permit.

On September 23, 2008, copies of the Notice of Air Pollution Comment Period and Public Hearing, the Fact Sheet, the Technical Summary, and the draft terms and conditions were placed on the Internet at the Michigan Department of Environmental Quality (MDEQ), Air Quality Division's (AQD) Home Page (<http://www.michigan.gov/deq>). Also, the AQD mailed postcards to persons who had previously expressed interest and had provided a complete mailing or email address. In addition, a notice announcing each Public Comment Period, Public Informational Meeting, and Public Hearing was placed in *The Alpena News* and the *Presque Isle Advance*. The notice provided pertinent information regarding the proposed action; the locations of available information; a telephone number to request additional information; the date, time, and location of the Public Informational Meeting and Public Hearing; the closing date of the Public Comment Period; and the address where written comments were being received.

Since October 1, 2008, two (2) panel informational sessions and five (5) public hearings have been held regarding the Permit to Install application for the proposed project.

On May 21, 2010, the MDEQ denied the Permit to Install application, due to a failure to demonstrate need for the proposed facility. Wolverine Power challenged that decision and in the Order dated January 28, 2011, the Missaukee County Circuit Court ruled that the alleged lack of need for the proposed project alone, separate from air quality concerns, was not a legal basis to deny the application. The court remanded it back to the MDEQ for further consideration and requiring them to make a decision. This informational meeting and hearing are in response to that remand, taking into account new regulations that became effective since the denial action. These regulations are the new 1-hour National Ambient Air Quality Standards for nitrogen dioxide and sulfur dioxide and the requirement to provide a BACT demonstration for greenhouse gases.

Approximately 4500 written comments were received during the Public Comment Periods and the hearings.

The remainder of this document is a listing of the significant comments received during the public comment period and hearing regarding the proposed permit and the Department's response. The first section discusses the comments received that resulted in changes to the final permit terms and conditions and the basis for each

change. The last section discusses the Department's response to all other significant comments that did not result in changes to the final permit.

This Response to Comments document fulfills the requirements specified in 40 CFR 124.17.

II. SUMMARY OF COMMENTS RESULTING IN CHANGES TO THE PERMIT

There are a significant number of changes to the permit. Many of the changes address issues raised in the public comments. Other changes were made because of modifications to the applicable rules and regulations or by MDEQ to clarify enforceability of the applicable requirements. Some permit condition changes are simply corrections of unintentional errors.

Except for the first few changes listed, the changes listed on the following pages will follow the order of conditions in the permit within each grouping. Condition changes made in response to comments are identified, and the section of this document where a more detailed response can be located is listed for each of those changes.

Common Abbreviations / Acronyms

Changes:

Page 3: MDEQ added the following abbreviations: SC = Special Condition; and PM2.5 = PM less than or equal to a nominal 2.5 micrometers, in diameter

Page 3: MDEQ changed the following abbreviation: PM10 = PM less than or equal to a nominal 10 micrometers, in diameter

General Conditions

Changes:

Page 4: MDEQ revised General Condition No. 5 due to a 2007 rule change. General Condition 5 now reads:

"The terms and conditions of this Permit to Install shall apply to any person or legal entity that now or hereafter owns or operates the process or process equipment at the location authorized by this Permit to Install. If the new owner or operator submits a written request to the Department pursuant to R 336.1219 and the Department approves the request, this permit will be amended to reflect the change of ownership or operational control. The request must include all of the information required by subrules (1)(a), (b), and (c) of R 336.1219 and shall be sent to the District Supervisor, Air Quality Division, Michigan Department of Environmental Quality. **(R336.1219)**"

Special Conditions

Entire Document Changes:

Pages 8 - 52: MDEQ removed all footnotes in the Emission Limit tables for each emission unit and insert language, "Test protocol will specify averaging time", in the appropriate cell under the Time Period/Operating Scenario column within the table.

Pages 34 - 52: MDEQ removed all footnotes in the Emission Limit tables for each emission unit and insert language, "...calculated on a dry gas basis", in the appropriate cell under the Limit column within the table.

Pages 8 - 52: MDEQ added PM 2.5 BACT limits. Emission limits were added for PM2.5 to all emission units which have PM10 limits.

Pages 1 – 53: MDEQ change applicable requirement of R 336.1299(e) to R 336.1299(2)(b). There was an error throughout the entire document referencing the applicable requirement for adoption of standards by reference for federal MACT requirements.

Pages 1 – 53: MDEQ added the following applicable requirements to each emission units requirement for a Malfunction Abatement Plan (MAP): R 336.1331, R 336.1910, R 336.1911, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21 (c), (d), & (j)

EUAUXBOILER

Condition Change:

Page 8: (Emission Limit Column for SC I.2, 1.3, and 1.6) MDEQ changed “lb/hr” to “pph”, to keep consistency throughout the document. Both units refer to the same meaning of pounds per hour.

Condition Change:

Page 8: (SC I.8) MDEQ defined HCl as “Hydrogen Chloride” in the Emission Limit Table, Pollutant column.

Comment:

Particulate matter limits for EUAUXBOILER does not include condensable fraction. Draft permit does not include complete particulate matter BACT limits for EUAUXBOILER.

Response:

Potential particulate matter, of all forms, from the distillate oil-fired equipment is expected to be very low, since the equipment will have limited use. However, PM2.5 emission limits representing BACT have been added to the auxiliary boiler.

Condition Change:

Page 8: (Added SC I.4 and Renumbered Emission Limit Table) MDEQ added a PM2.5 emission limit representing BACT for EUAUXBOILER.

Comment:

Proposed EUAUXBOILER BACT emission limits for PM, PM10, NOx, CO, VOC and HCL exclude periods of startup and shutdown; permit does not define startup and shutdown, or contain recordkeeping or reporting requirements for startup and shutdown.

Response:

MDEQ agrees with the commenter, that BACT emission limits should not be excluded during periods of startup and shutdown. Also, the MDEQ agrees with the commenter that the draft permit does not define startup and shutdown. However, MDEQ does not believe it is necessary to define startup and shutdown when there is not a way to measure continuous heat input to the boiler. When the boiler emissions were reviewed it was determined that BACT, for a small boiler (less than 100 MMBtu/hr) burning ultra low sulfur fuel and limited operation, did not include continuous emission monitors which would measure heat input. Therefore, MDEQ changed previously proposed lb/MMBtu limits to lb/hour limits based on

the maximum heat input of EUAUXBOILER and deleted all exclusions for startups and shutdowns from the limits. MDEQ also added a special condition which minimizes emissions during startup and shutdown.

Condition Change:

Page 8: (SC I.1 through I.8) MDEQ changed previously proposed lb/MMBtu emission limits to lb/hr limits for PM, VOC, and HCL. The limits for the pollutants were changed as follows:

Pollutant	Current Limit (lb/MMBtu)	Proposed Limit (lb/hr)
PM	0.0015	0.11
VOC	0.0042	0.30
HCL	0.0007	0.050

Condition Change:

Page 9: (Added SC III.4) MDEQ added a special condition to the Process/Operational Restrictions to minimize excess emissions during startup and shutdown. The condition reads as follows:

“The permittee shall not operate EUAUXBOILER unless an acceptable plan that describes how emissions will be minimized during all startups and shutdowns has been submitted to the AQD District Supervisor. The plan shall incorporate procedures recommended by the equipment manufacturer as well as incorporating standard industry practices and good combustion control. **(R 336.1911, R 336.1912, R 336.2802, 40 CFR 52.21)**”

Comment:

The proposed EUAUXBOILER emission limits do not contain limits for sulfur dioxide. There should also be appropriate monitoring, recordkeeping and reporting requirements.

Response:

The proposed draft permit does not include emission limits for sulfur dioxide. However, it does include material limits for the sulfur content in the fuel, required by the NSPS. Also, there are monitoring and recordkeeping requirements for fuel supplier certification records. When the auxiliary boiler emissions were reviewed it was determined that BACT, for a small boiler (less than 100 MMBtu/hr) burning fuel oil with a low sulfur content and limited operation, was to limit only the sulfur content of the fuel since that is a limit which is more enforceable as practical manner. The fuel oil company is required to do an analysis of the fuel and to certify it. This allows more frequent monitoring and recordkeeping of the fuel which is burned.

Condition Change:

Page 9: (SC II.1) MDEQ deleted from the beginning of SC II.1: “After the year 2010”. That statement refers to the sulfur content in the fuel if the boiler were to be operating before the year 2010.

Condition Change:

Page 11: (Added SC IX.1) MDEQ added special condition to ensure the permittee follows all federal New Source Performance Standards. The condition reads as follows:

“The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and Dc, as they apply to EUAUXBOILER. **(40 CFR Part 60 Subparts A & Dc)**”

EUEMGGEN

Comment:

The particulate matter limits for EUEMGGEN does not include condensable fraction. Draft permit does not include complete particulate matter BACT limits for EUEMGGEN.

Response:

Potential particulate matter, of all forms, from the distillate oil-fired equipment is expected to be very low, since the equipment will have limited use. However, PM10 and PM2.5 emission limits, which include the condensable fraction, representing BACT have been added to the emergency generator.

Condition Change:

Page12: (Renumbered Emission Limits and Added SC I.2, I.3, 1.8, and 1.9) MDEQ added PM10 and PM2.5 emission limits representing BACT for EUEMGGEN.

Condition Change:

Page 13: (SC II.1) MDEQ deleted reference to the sulfur content of diesel fuel used prior to October 2010. The condition now reads as follows:

“The permittee shall only burn diesel fuel, in EUEMGGEN, with a maximum sulfur content of 15 ppm per gallon, and a minimum centane index of 40; or a maximum aromatic content of 35 percent by volume. **(40 CFR 60.4207(b))**”

Comment:

Proposed draft conditions for EUEMGGEN do not define startup and shutdown, or contain recordkeeping or reporting requirements for startup and shutdown.

Response:

MDEQ agrees emissions should be minimized during startup and shutdown. However, MDEQ does not believe it is necessary to define startup and shutdown when there is not a way to measure continuous heat input to the generator. Emergency generators are expected to run no more than 500 hours per year which includes startup and shutdown.

Condition Change:

Page 14: (Added SC III.6) MDEQ added a special condition to the Process/Operational Restrictions to minimize excess emissions during startup and shutdown. The condition reads as follows:

“The permittee shall not operate EUEMGGEN unless an acceptable plan that describes how emissions will be minimized during all startups and shutdowns has been submitted to the AQD District Supervisor. The plan shall incorporate procedures recommended by the equipment manufacturer as well as incorporating standard industry practices and good combustion control. **(R 336.1911, R 336.1912, R 336.2802, 40 CFR 52.21)**”

Condition Change:

Page 15: (Added SC IX.1) MDEQ added a special condition to ensure the permittee follows all federal New Source Performance Standards. The condition reads as follows:

“The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and IIII, as they apply to EUEMGGEN. **(40 CFR Part 60 Subparts A & IIII)**”

Condition Change:

Page 15: (Added SC IX.2) MDEQ added a special condition to ensure the permittee follows all National Emission Standards for Hazardous Air Pollutants. The condition reads as follows:

“The permittee shall comply with all provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR, Part 63, Subpart A and Subpart ZZZZ, for Stationary Reciprocating Internal Combustion Engines, as they apply to EUEMGGEN. **(40 CFR, Part 63, Subparts A and ZZZZ)**”

EUFIREPUMP

Comment:

The particulate matter limits for EUFIREPUMP does not include condensable fraction. The draft permit does not include complete particulate matter BACT limits for EUFIREPUMP.

Response:

Potential particulate matter, of all forms, from the distillate oil-fired equipment is expected to be very low, since the equipment will have limited use. However, PM10 and PM2.5 emission limits, which include the condensable fraction, representing BACT have been added to the emission limit table for EUFIREPUMP.

Condition Change:

Page16: (Added SC I.2 and 1.3 and Renumbered Emission Limit Table) MDEQ added a PM10 and PM2.5 emission limit representing BACT for EUFIREPUMP.

Condition Change:

Page 16: (SC II.1) MDEQ deleted reference to the sulfur content of diesel fuel used prior to October 2010. The condition now reads as follows:

“The permittee shall only burn diesel fuel, in EUFIREPUMP, with a maximum sulfur content of 15 ppm per gallon, and a minimum centane index of 40; or a maximum aromatic content of 35 percent by volume. **(40 CFR 60.4207(b))**”

Comment:

The proposed draft conditions for EUFIREPUMP do not define startup and shutdown, or contain recordkeeping or reporting requirements for startup and shutdown.

Response:

MDEQ agrees emissions should be minimized during startup and shutdown. However, MDEQ does not believe it is necessary to define startup and shutdown when there is not a

way to measure continuous heat input to the engine fire pump. Emergency fire pumps are expected to run no more than 500 hours per year which includes startup and shutdown.

Condition Change:

Page 17: (Added SC III.6) MDEQ added a special condition to the Process/Operational Restrictions to minimize excess emissions during startup and shutdown. The condition reads as follows:

“The permittee shall not operate EUFIREPUMP unless an acceptable plan that describes how emissions will be minimized during all startups and shutdowns has been submitted to the AQD District Supervisor. The plan shall incorporate procedures recommended by the equipment manufacturer as well as incorporating standard industry practices and good combustion control. **(R 336.1911, R 336.1912, R 336.2802, 40 CFR 52.21)**”

Condition Change:

Page 18: (Added SC IX.1) MDEQ added special condition to ensure the permittee follows all federal New Source Performance Standards. The condition reads as follows:

“The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and IIII, as they apply to EUFIREPUMP. **(40 CFR Part 60 Subparts A & IIII)**”

EUBLACKSTART

Comment:

Particulate matter limits for EUBLACKSTART does not include condensable fraction. Draft permit does not include complete particulate matter BACT limits for EUBLACKSTART.

Response:

Potential particulate matter, of all forms, from the distillate oil-fired equipment is expected to be very low, since the equipment will have limited use. However, PM10 and PM2.5 emission limits, which include the condensable fraction, representing BACT have been added to the emission limit table for EUBLACKSTART.

Condition Change:

Page 19: (Added SC I.2 and I.3 and Renumbered Emission Limit Table) MDEQ added a PM10 and PM2.5 emission limits representing BACT for EUBLACKSTART.

Condition Change:

Page 20: (Changed SC II.1) MDEQ deleted from the beginning of SC II.1: “After the year 2010”. That statement refers to the sulfur content in the fuel if the equipment were to be operating before the year 2010.

Comment:

The proposed draft conditions for EUBLACKSTART do not define startup and shutdown, or contain recordkeeping or reporting requirements for startup and shutdown.

Response:

MDEQ agrees emissions should be minimized during startup and shutdown. However, MDEQ does not believe it is necessary to define startup and shutdown when there is not a way to measure continuous heat input to the black start turbine. Emergency turbines are expected to run no more than 500 hours per year which includes startup and shutdown.

Condition Change:

Page 20: (Added SC III.4) MDEQ added a special condition to the Process/Operational Restrictions to minimize excess emissions during startup and shutdown. The condition reads as follows:

“The permittee shall not operate EUBLACKSTART unless an acceptable plan that describes how emissions will be minimized during all startups and shutdowns has been submitted to the AQD District Supervisor. The plan shall incorporate procedures recommended by the equipment manufacturer as well as incorporating standard industry practices and good combustion control. **(R 336.1911, R 336.1912, R 336.2802, 40 CFR 52.21)**”

Condition Change:

Page 22: (Added SC IX.1) MDEQ added special condition to ensure the permittee follows all federal New Source Performance Standards. The condition reads as follows:

“The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and KKKK, as they apply to EUBLACKSTART. **(40 CFR Part 60 Subparts A & KKKK)**”

FGCFB Emission Limits

Condition Change:

Page 26: (Limit Column of SC I.10 and I.16) MDEQ deleted “excluding periods of startup and shutdown” from the New Source Performance Standard (NSPS) which should be met at all times.

Condition Change:

Page 26: (Underlying Applicable Requirement Column of SC I.18) MDEQ added R 336.1299(2)(b), to ensure the requirement for MACT is met during periods of startup and shutdown for VOC.

Comment:

The proposed draft conditions include conflicting limits for the same load levels, when only the lower limit arguably may constitute BACT. Also, a late submittal of a startup, shutdown plan violates the CAA requirements.

Response:

Based on the comments received the MDEQ removed intermediate load conditions from the permit. The MDEQ believes that Wolverine did not provide adequate information to substantiate the necessity for such limits and that the limits appeared to allow Wolverine to operate in a malfunction state of operation without calling it a malfunction. The startup, shutdown, and malfunction plans will be submitted to the district supervisor before operation

of the plant. Since the plan is required by the permit but not part of the permit, it allows the district supervisor to require the permittee to quickly make changes to the MAP if it fails to address a malfunction.

Condition Change:

Pages 25 -27: MDEQ removed intermediate load special conditions for NO_x, CO, SO₂, and VOC. As a result, all emission limits were renumbered in the Emission Limit Table.

Condition Change:

Page 27: (SC I.22) MDEQ added a more restrictive emission limit for Hydrogen Fluoride (HF), 0.00014 lb/MMBtu heat input, replaces previous proposed limit of 0.00030 lb/MMBtu heat input. This change is made in response to a comment. A detailed response can be found in the "Maximum Achievable Control Technology (MACT) Review" Section of this document.

Condition Change:

Page 27: (SC I.25 Footnote 1) MDEQ changed "CEMs" to "CERMs" and added the language "as defined in 40 CFR Part 98 for non-CO₂e GHGs". Change was made for enhanced emissions monitoring. CEMs measures concentration of the flue gases and CERMs measures the concentration plus the flow of the flue gas to monitor the emission rate. The footnote now reads as follows:

"¹Emissions shall be calculated based on CO₂ CERMS data and fuel factors for non-CO₂ GHGs, as defined in 40 CFR Part 98."

FGCFB Material Limits

Condition Change:

Pages 27, 28: (SC II.1) MDEQ changed No. 2 fuel oil to ultra low diesel fuel based on the NSPS requirements of other diesel fueled equipment at the proposed facility which requires the use of this type of fuel. Therefore, ultra low sulfur diesel fuel will be available at the site. Also, deleted previous SC II.6 since the condition is now covered by SC II.1.

FGCFB Process/Operational Restrictions

Condition Change:

Page 29: (Added SC III.1) MDEQ added an additional requirement to the start-up provisions of each boiler in SC III.1 to ensure both boilers are not starting up at the same time. This qualifier is necessary to ensure protection of the NAAQS. The condition reads as follows:

"The permittee shall not operate both EUCFB1 and EUCFB2 simultaneously anytime during a start-up operation. Start-up operations for each boiler included in FGCFB shall not exceed 24 hours. Shutdown operations for each boiler included in FGCFB shall not exceed 8 hours. FGCFB shall not exceed 12 cold start-ups and shutdowns for each boiler in a 12-month time period. Start-up is defined as the period of time from initiation of combustion firing until the unit reaches steady state operation (i.e. minimum of 50% load). Cold start-up is defined as a start-up after 48 or more hours following the last fuel input to the boiler. Shutdown is defined as that period of time from the initial lowering of the boiler output below 50% of the maximum heat input, until the point at which the combustion process has stopped and the bed material fluidizing air has been discontinued. (R 336.2810, 40 CFR 52.21(j))"

Condition Change:

Page 29: (Added SC III.5) MDEQ added a special condition to the Process/Operational Restrictions to minimize excess emissions during startup and shutdown. The condition reads as follows:

“The permittee shall not operate FGCFB unless an acceptable plan that describes how emissions will be minimized during all startups and shutdowns has been submitted to the AQD District Supervisor. The plan shall incorporate procedures recommended by the equipment manufacturer as well as incorporating standard industry practices and good combustion control. (R 336.1911, R 336.1912, R 336.2802, 40 CFR 52.21)”

FGCFB Design/Equipment Parameters

Condition Change:

Page 27, 28: (SC IV.1 and IV.2) MDEQ changed the special conditions by adding parenthesis around “spray dryer absorber”. The condition reads as follows:

“The permittee shall not operate EUCFB1 unless the selective non-catalytic reduction system (SNCR), pulse jet fabric filter with polyphenylene sulfide bags, polishing scrubber (spray dryer absorber), and sorbent injection system is installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved malfunction abatement plan (MAP) for EUCFB1 as required in Process/Operational Restriction SC III.2. (R 336.1225, R 336.1299(2)(b), R 336.1901, R 336.1910, R 336.2810, 40 CFR 52.21(j))”

FGCFB Monitoring/Recordkeeping

Condition Change:

Page 31: (SC VI.4) MDEQ changed the special condition by adding the word “volumetric” to the exhaust gas flow rate. It now reads as follows:

“The permittee shall install, calibrate, maintain and operate in a satisfactory manner a device to monitor and record the exhaust gas volumetric flow rate from each boiler included in FGCFB on a continuous basis. The monitor shall be operated in accordance with procedures outlined in Appendix B attached and in 40 CFR 60.49Da(m). (R 336.2810, 40 CFR 52.21(j), 40 CFR 60.49Da)”

Condition Change:

Page 30, 31: (from draft dated 9/9/2008, deleted SC VI.11, 12, 13, 14, and 15) MDEQ deleted previous draft recordkeeping requirements for VOC, Pb, H₂SO₄, HCl and As, since it is not necessary to calculate monthly emissions for those pollutants. The emission limits require stack testing to verify emission rate, not to determine an annual average. Records of stack test results are required to be kept in SC VI.12.

Condition Change:

Page 32: (SC VI.12) MDEQ added subparts e, f, and g to specify necessary record keeping ensuring compliance with all applicable requirements of the permit. Also, all applicable

requirement numbers were added to the special condition. Special condition VI.12 now reads as follows:

“The permittee shall maintain records for FGCFB for information necessary for all notifications and reports as specified in these special conditions as well as that information necessary to demonstrate compliance with the emission limits of this permit. This information shall include, but shall not be limited to, the following:

- a) Compliance tests and any testing required under 40 CFR Subpart Da or the conditions of this permit
- b) Monitoring data
- c) Heat input calculations
- d) Fuel analysis including identification, type, heating value (Btu/lb), and the amounts of all fuels combusted in FGCFB on a daily average basis
- e) Total gigawatt-hours of energy produced on a monthly basis
- f) Records of the duration of all times FGCFB is operated under startup or shutdown conditions as defined in SC III.1
- g) All records required by 40 CFR§60.7 and §60.52a
- h) All calculations necessary to demonstrate compliance with the limits contained in this permit, or the reporting requirements contained in Appendix C of this permit.

All of the above information shall be stored in a format acceptable to the Air Quality Division, shall be maintained for a period of at least five years, and shall be consistent with the requirements of 40 CFR 60.7(f). **(R 336.1205(1)(a), R 336.1225, R 336.1228, R 336.1229(2)(b), R 336.1299(2)(b), R 336.1301, R 336.1331, R 336.1401, R 336.1702(a), R 336.1901, R 336.1912, R 336.2802(4), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(a)(2), 40 CFR 52.21(c),(d), & (j), 40 CFR 60.42Da, 40 CFR 60.7(f))”**

FGCFB Reporting

Condition Change:

Page 31: (SC VII.1) MDEQ added the underlying applicable requirement of “**40 CFR 60.51Da(a)**” to the condition. The condition refers to Appendix C-1 reporting which is required by 40 CFR 60.51Da(a) in addition to 40 CFR 60.51Da(b).

FGCFB Other Requirements

Condition Change:

Page 33: (Added SC IX.3 and changed the old SC IX.3 to SC IX.4) MDEQ added special condition to ensure the permittee follows all federal New Source Performance Standards. The condition reads as follows:

“The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and Da, as they apply to FGCFB. **(40 CFR Part 60 Subparts A & Da)**”

Material Handling Operations

Condition Change:

Page 45, 48, and 50: (Added SC IX.1 and deleted condition from Process Operational Limits) MDEQ added special condition to ensure the permittee follows all federal New Source Performance Standards. The condition reads as follows:

“The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and Y, as they apply to (EMISSION UNIT ID). **(40 CFR Part 60 Subparts A & Y)**”

Comment:

With regard to the fuel crusher (EUFUELCRUSHER) for PM and PM10, the draft conditions reference General Condition 13 which states that Michigan may require performance testing for emission control. However, Subpart Y 40 CFR 60.252(c) references 40 CFR 60.8 which requires performance testing within 180 days of start up and a written report to be submitted. The draft permit should be amended to reflect the federal requirements found at 40 CFR 60.252(c).

Response:

EUSOLIDFUELHANDLING, EUFUELCRUSHER, and EUFUELSILO are all subject to NSPS Y and the proposed permit reflects that applicability. However the requirement for mandatory visible emission testing under NSPS Y was not included in the draft permit. The requirement was added to the special conditions.

Condition Change:

Page 45, 48, and 50: (Added SC V.1) MDEQ added the requirement for permittee to conduct visible emissions tests for emission units EUSOLIDFUELHANDLING, EUFUELCRUSHER, and EUFUELSILO. Special Condition reads as follows:

“Within 180 days after initial start-up of (EMISSION UNIT ID), the permittee shall conduct visible emissions tests from (EMISSION UNIT ID) by testing at owner's expense, in accordance with federal Standards of Performance for New Stationary Sources 40 CFR Part 60 Subparts A and Y. No less than 60 days prior to testing, the permittee shall submit a complete test plan to the AQD. The AQD must approve the final plan prior to testing. Verification of emission rates includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test. **(40 CFR Part 60 Subparts A & Y)**”

Comment:

The permit is not practically enforceable because it relies on a yet-to-be completed Malfunction Abatement Plan (MAP) and Fugitive Emissions Control Plan (FECP) and because the permit does not include the contents of the MAP and FECP. The MAP violates the public participation requirements for PSD because it will not be completed until after the permit is issued. The FECP violates the public participation requirements for PSD permits because it does not have to be completed until 180 days after initial start-up of the covered equipment.

Response:

The requirements of the MAP and the FECP are incorporated into the permit and are not separate, unenforceable provisions. For example, Special Condition III.2 for EULIMESTONE states that Wolverine shall not operate EULIMESTONE unless an MAP as described in Rule 911(2) is implemented and maintained. Similarly, Special Condition III.1 for EULIMESTONE states the FECP shall be implemented, and maintained.

The documents published for public comment included a preliminary MAP. The preliminary MAP provides a template for the MAP requirements and identifies the plan components, including equipment to be inspected, inspection frequency, spare parts inventory, and remedial actions to be undertaken if a malfunction occurs. The preliminary MAP also explains that the final information as to such components cannot be defined until the equipment vendors are selected and the facility design has progressed to a point that allows definition.

The documents published for public comment also include a preliminary FECP. As stated in that document, the requirements in the FECP may be changed once the actual equipment is selected and installed. For example, the preliminary FECP states that fly ash in storage silos shall be transferred onto haul trucks using a wet ash unloading system to minimize fugitive dust. Additional requirements (including how that system will operate to keep the ash wet) will be incorporated into the FECP after the wet ash unloading system is selected and installed.

It is not technically feasible to develop the final requirements of the MAP and the FECP as part of the pre-construction review because they are dependent on facility-specific, as-built site conditions. The opportunity the public was given to comment on the preliminary MAP and FECP satisfies the public participation requirements for PSD permits.

Condition Change:

Pages 34 through 53: (SC III.1) As part of this comment review, MDEQ modified the previous language for requiring a fugitive dust control program from EULIMESTONE, EULIMESTONEPREP, EUBEDASH, EUFLYASH, EUSOLIDFUELHANDLING, EUFUELCRUSHER, and EUFUELSILO.

The revised Special Condition III.1 now reads as follows:

“Within 180 days of initial start-up of (EMISSION UNIT ID) the permittee shall submit to the AQD District Supervisor a program for continuous fugitive emissions control for all material handling operations. The program shall be reviewed and approved by the AQD District Supervisor and is implemented and maintained. If at any time the fugitive dust control program fails to address or inadequately addresses an event that meets the characteristics of a revision or update, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all

applicable emission limits. **(R 336.1371, R 336.1901, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21 (c), (d), & (j))**

Condition Change:

Pages 34 through 53: (SC III.2) As part of the comment review, MDEQ added language requiring a malfunction abatement plan (MAP) from EULIMESTONE, EULIMESTONEPREP, EUBEDASH, EUFLYASH, EUSOLIDFUELHANDLING, EUFUELCRUSHER, and EUFUELSILO. The Special Condition III.2 reads as follows:

“The permittee shall not operate (EMISSION UNIT) unless a malfunction abatement plan (MAP) as described in Rule 911(2) is implemented and maintained. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits. **(R 336.1331, R 336.1910, R 336.1911, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21 (c), (d), & (j))**”

Condition Change:

Pages 34 through 53: (SC IV.1) As part of the comment review, special conditions requiring the installation, operation and maintenance of emissions control equipment were moved from the “Process/Operational Restriction(s)” section to the “Design/Equipment Parameter(s)” section. This occurred in the following Emission Units: EULIMESTONE; EULIMESTONEPREP; EUBEDASH; EUFLYASH; EUSOLIDFUELHANDLING; EUFUELCRUSHER; and EUFUELSILO. The special condition reads as follows:

“The permittee shall not operate (specific portion of EMISSION UNIT) unless the (specific control equipment) is installed and/or implemented, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with a malfunction abatement plan (MAP), as required by Special Condition III.2. **(R 336.1901, R 336.1910, R 336.1911, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21 (c), (d) & (j))**”

Condition Change:

Pages 33 through 53: (SC IX.1) As part of the comment review, special conditions referencing general compliance for an applicable New Source Performance Standard (NSPS) were moved from the “Process/Operational Restriction(s)” section to the “Other Requirement(s)” section. This occurred in the following Emission Units: EULIMESTONE; EULIMESTONEPREP; EUSOLIDFUELHANDLING; EUFUELCRUSHER; and EUFUELSILO. The special condition reads as follows:

“The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and (SUBPART), as they apply to (EMISSION UNIT). **(40 CFR Part 60 Subparts A & (SUBPART))**”

Condition Change:

Pages 33 through 53: MDEQ made changes to the permit underlying applicable requirements (UAR). Specifically, removal of 40 CFR 52.21(c) & (d) and MAPC Rules 336.2803, and 336.2804 from any allowable opacity limitations from emission units EULIMESTONE, EULIMESTONEPREP, EUBEDASH, EUFLYASH, EUSOLIDFUELHANDLING, EUFUELCRUSHER, and EUFUELSILO. This particular change was due to the recognition that opacity limits are neither subject to the PSD increment analysis nor any NAAQS demonstration.

Condition Change:

Pages 46 through 52: The previously listed UAR for Opacity Limits was changed from 40 CFR 60.252(c) to 40 CFR 60.254 for the following emission units: EUSOLIDFUELHANDLING, EUFUELCRUSHER, and EUFUELSILO. During the comment review, the Federal EPA promulgated a revised NSPS Y and the appropriate UAR citation was changed.

Condition Change:

Pages 34 and 37: MDEQ changed the opacity limit from 10% to 7% for drop and transfer points in EULIMESTONE and EULIMESTONEPREP. During the comment review, the federal EPA promulgated revisions to the Standards of Performance for Non-metallic Mineral Processing Plants (NSPS OOO), which lowered the opacity emission limitations for drop and transfer points from 10% to 7%.

III. SUMMARY OF COMMENTS

A. Alternative Analysis

Comment:

Wolverine has not satisfied the burden of demonstrating a need for or lack of a feasible and prudent cleaner alternative to the proposed coal plant. In very general terms, the filing fails to demonstrate there are not feasible and prudent alternatives. Issuance of the permit based on Wolverines' submittal would be arbitrary and capricious.

Response:

On June 12, 2009, in response to a request from MDEQ, Wolverine submitted an Electric Generation Alternatives Analysis ("EGAA"). The EGAA addressed both coal burning alternate technologies and non-coal burning alternative technologies. The MDEQ determined that, from a cost of electricity standpoint, the proposed facility represents the least expensive technology to implement and the alternative technologies presented in the EGAA are either not viable or are substantially more expensive.

In response to the question of demonstrating need, the MDEQ originally denied the air permit to install on May 21, 2010. Key in that denial was a determination from the Michigan Public Service Commission (MPSC) that the applicant had failed to demonstrate a need for the additional power as part of its EGAA. Wolverine challenged this decision and in its Opinion and Order dated January 28, 2011 in Case No. 10-7686-CE, the Missaukee County Circuit Court ruled that the alleged lack of need for the proposed facility alone, separate from air quality concerns, is not a legal basis to deny the permit application. The court concluded

that the state overstepped its authority, and gave the state 60 days to re-review the application.

Before providing a more detailed rationale regarding the MDEQ review of the alternatives analysis, it is appropriate to provide a background on the requirements for performing an analysis of alternative electricity generating technologies.

Specific regulatory guidance on performing an alternative analysis for new facilities locating in attainment areas are not provided for in existing federal or state environmental rules. The basis for an alternatives analysis is contained in Section 165(a)(2) of the Clean Air Act. That provision states that no major emitting facility on which construction is commenced after August 7, 1977, may be constructed in an attainment area unless, among other things:

...the proposed permit has been subject to a review in accordance with this section, the required analysis has been conducted in accordance with regulations promulgated by the Administrator, and a public hearing has been held with the opportunity for interested persons including representatives of the Administrator to appear and submit written or oral presentation on the air quality impact of such source, **alternatives thereto**, control technology requirements, and other appropriate considerations; [Emphasis added]

This provision has been interpreted by the United States Environmental Protection Agency (EPA) Environmental Appeals Board to require a permitting agency to respond to comments raised during public comment regarding alternatives to a proposed facility, and to give the agency the discretion as to how to conduct this review.

Language similar to that in Section 165(a)(2) is contained in Rule 1817(2)(e) of the Michigan Air Pollution Rules. The rule requires the MDEQ to do several things after receiving a technically complete permit application, including:

Provide opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality impact of the major source, **alternatives to it**, the control technology required, and other appropriate considerations. [Emphasis added]

As previously stated, on June 2, 2009, the MDEQ requested that Wolverine provide an analysis of alternatives in response to public comment received on the draft air permit to install. The EGAA was submitted by Wolverine addressing comments received on alternatives to the proposed facility.

In cooperation with the MPSC, the EGAA was reviewed with regard to alternatives. Although, the MPSC concluded that 'the coal-fired generating plant is one alternative out of a range of alternatives that may be used to fill the projected capacity need', costs associated with the alternatives were reviewed and deemed prohibitive. The MPSC suggested that alternatives such as energy efficiency and renewable resources may be used.

The EGAA evaluated a number of different alternative technologies. In very general terms these alternatives can be grouped into two categories: coal burning technologies and non-coal burning alternative technologies. For coal burning technologies a number of coal burning technologies were evaluated and costs of implementing the technologies were

estimated in the EGAA. The coal burning technologies considered included Advanced Supercritical Pulverized Coal, Subcritical Pulverized Coal, Subcritical Circulating Fluidized Bed, Integrated Gasification combined Cycle and Ultra Supercritical Pulverized Coal. The non-coal burning technologies considered included natural gas combined cycle, natural gas combustion turbine, on-shore wind, off-shore wind, small wind, small biomass – wood, solar photovoltaic, hydroelectric, nuclear, geothermal, and landfill gas.

The MDEQ reviewed the assumptions and methodology used by Wolverine in arriving at the costs of the various technologies. The MDEQ determined the costs of the alternatives to the proposed facility are substantially more expensive than the proposed facility itself and are cost prohibitive. In addition, some of the technologies are not available (e.g. geothermal) or have limited availability (e.g. combined heat and power, pumped storage).

Comment:

Even looking just at coal-fired generation, there are feasible and prudent alternatives available for achieving lower environmental impacts than the proposed coal plants, such as IGCC.

Response:

Coal-burning technologies other than CFB boilers are available, as discussed in a previous response. MDEQ evaluated these technologies during the permit review process, including IGCC. Other existing coal combustion technologies are not designed to burn the multiple fuels that Wolverine is proposing to use. Wolverine, as a part of their alternatives analysis, evaluated the cost of these alternate coal firing alternatives and made the determination that the chosen technology is the most cost effective for the variety of fuels they are proposing to use. MDEQ concurred with this determination.

In regards to IGCC, the applicant provided additional information as a part of the best available control technology (BACT) review. The MDEQ rejected IGCC from further analysis as it was determined to be cost prohibitive under this control technology review. The MDEQ has similarly rejected IGCC as cost prohibitive for purpose of the analysis under Section 165(a)(2) of the Clean Air Act and Rule 1817(2)(e) of Michigan's Air Pollution Control Rules.

Comment:

The public has not been provided the full opportunity for meaningful public participation required by the Clean Air Act and state regulations. The public has not been given the opportunity to review the alternatives analysis and needs analysis provided by Wolverine.

Response:

Neither Section 165(a)(2) of the Clean Air Act nor Rule 187(2)(e) of Michigan's Air Pollution Control Rules require additional public comment. Nevertheless, the MDEQ, in order to provide the public with all pertinent issues relating to the evaluation of the permit, announced a 30-day public comment period. This comment period was announced on the MDEQ website (see <http://www.deq.state.mi.us/aps/cwerp.shtml>). This public comment period was scheduled concurrently with the public hearing announced by the MPSC public comment period. All information related to the EGAA was made publicly available during this public notice period either on the MDEQ website or via the MPSC e-docket.

Comment:

The EGAA fails to recognize that it is possible to construct nothing and still meet Michigan's foreseeable generation requirements.

Response:

This comment is directed at the issue of whether there is a need for the facility. In its Opinion and Order dated January 28, 2011 in Case No. 10-7686-CE, the Missaukee County Circuit Court ruled that the alleged lack of need for the proposed facility alone, separate from air quality concerns, is not a legal basis to deny the permit application.

Comment:

Wolverine assumed an estimated cost for wind power that is at least 1.5 times higher than national averages and recent estimates.

Response:

Many of the factors that are used to estimate the costs of electrical generation are volatile and in a constant state of flux. Wolverine estimated the cost of power generated by a wind farm would be about 11.1 cents/kWh¹. Since a wind farm alone is not suitable for baseload need, this cost includes a natural gas simple-cycle technology for those intermittent times that the wind is not blowing. Assuming that the assertion made by the commenter is correct, if the cost for wind power was adjusted downwards, the national average cost for wind power would equate to approximately 7.4 cents/kWh, which is the same cost of the chosen CFB boiler technology firing petroleum coke/PRB/Biomass Blend.² Also, consideration would need to be given to the amount of land required for a wind farm. For every 1 MW of power there needs to be at least 50 acres of land available. Therefore, to achieve a 600 MW capacity there would need to be at least 50 square miles of land available.

Comment:

Section 165(a)(2) of the Clean Air Act, which requires as part of the permitting for a proposed major source that the public be provided the opportunity to submit testimony on the "air quality impacts of such source, alternatives thereto, control technology requirements, and other appropriate considerations." As the agency is required to respond to comments submitted by the public, MDEQ must substantively address the alternatives issues raised in these and other public comments. In addition, this language has long been interpreted to grant a permitting authority broad discretion to evaluate need, consider alternatives (including the "no build" alternative), conduct or require additional analyses, and impose permit conditions beyond the baseline requirements of BACT in order to protect air quality. *In re Prairie State Generating Co.*, PSD Appeal No. 05-05, quoting U.S. EPA Draft NSR Manual, 1990 ("NSR Manual"), MDEQ may consider a no-build option under Section 165(a)(2) of the Act, which provides MDEQ with the authority to deny a PSD permit based on policy considerations related to CO₂.¹⁷ While Section 165(a)(2) is designed primarily to ensure that the public's participation rights are

¹ See "Wolverine Power Cooperative Electric Generation Alternatives Analysis for the proposed Permit to Install (PTI) No. 317-07 For Circulating Fluidized Bed Coal Boilers at Rogers City, Michigan, Docket Number: U16000, Staff Report to the Michigan Department of Environmental Quality, Page 36.

² See "Wolverine Power Cooperative Electric Generation Alternatives Analysis for the proposed Permit to Install (PTI) No. 317-07 For Circulating Fluidized Bed Coal Boilers at Rogers City, Michigan, Docket Number: U16000, Staff Report to the Michigan Department of Environmental Quality, Page 39.

meaningful, MDEQ is not limited to issues raised by the public, but instead may consider or require alternatives, evaluations of need, and additional permit conditions on its own.

Response:

As previously stated, discretion is granted to the reviewing authority as to how to respond to comments raised on alternatives. This position is supported in the Prairie State case cited by the commenter. The MDEQ requested Wolverine address the question of alternatives raised during public comment and Wolverine responded with submittal of the EGAA. Wolverine, as a part of their alternatives analysis, evaluated the cost of coal firing alternatives and made the determination that the chosen technology is the most cost effective for the variety of fuels they are proposing to use. MDEQ concurred with this determination. As to the question of need or a 'no build' option, in its Opinion and Order dated January 28, 2011 in Case No. 10-7686-CE, the Missaukee County Circuit Court ruled that the alleged lack of need for the proposed facility alone, separate from air quality concerns, is not a legal basis to deny the permit application.

Comment:

We are sorry to see MDEQ misapplying the 28th Circuit Court ruling of Jan. 28. That ruling turns entirely on a failure by the MDNRE PTI denial letter to specifically tie questions about "need" to concerns about air quality – a tie that is plain in the administrative record, but not explicitly stated in the letter. In fact the ruling concedes that if the denial letter had taken that one final and obvious step, both it and the MDEQ decision to deny would have passed legal muster. So the decision to exclude from these new hearings further consideration of "need" and, much more to the legal and practical point, of the ready availability of cleaner alternatives for meeting future base load requirements, ignores what the circuit court ruling and federal and state laws actually say.

Response:

At the time of the May 21, 2010 denial, MDEQ had determined that the proposal by Wolverine met all applicable air quality rules and regulations with the exception of failing to demonstrate need. Therefore, it is incorrect to say that the MDEQ is misapplying the Circuit Court ruling. In its Opinion and Order dated January 28, 2011 in Case No. 10-7686-CE, the Missaukee County Circuit Court ruled that the alleged lack of need for the proposed facility alone, separate from air quality concerns, is not a legal basis to deny the permit application. MDEQ has evaluated the proposal and has determined that the project meets all applicable state and federal air quality requirements.

Comment:

The analysis of need is very closely tied to a requirement for alternatives analysis. That requirement for an alternative analysis exists both under the Federal Clean Air Act as well as state pollution law and regulations. And that requires the state to choose a no-build scenario.

Response:

The MDEQ requested Wolverine address the question of alternatives raised during public comment and Wolverine responded with submittal of the EGAA. Wolverine, as a part of their alternatives analysis, evaluated the cost of coal firing alternatives and made the determination that the chosen technology is the most cost effective for the variety of fuels they are proposing to use. MDEQ concurred with this determination. As to the question of

need or a 'no build' option, in its Opinion and Order dated January 28, 2011 in Case No. 10-7686-CE, the Missaukee County Circuit Court ruled that the alleged lack of need for the proposed facility alone, separate from air quality concerns, is not a legal basis to deny the permit application.

B. MEPA/Rule 901

Comment:

The emission of carbon dioxide (CO₂) and other greenhouse gases (GHGs) from the proposed facility will pollute, impair and destroy natural resources by exacerbating climate change. The impacts on public health and the environment from climate change are severe and widespread. Section 1705(a)(2) of MEPA requires that the MDEQ deny the permit application if there is a feasible and prudent alternative that would avoid or minimize the effect on climate change from the proposed facility.

Response:

The focus of the Michigan Environmental Protection Act (MEPA) is on the conduct of the permit applicant as opposed to emissions from other facilities.³ Section 1705(2) of MEPA states:

In administrative, licensing, or other proceedings, and in any judicial review of such a proceeding, the alleged pollution, impairment, or destruction of the air, water or other natural resources, or the public trust in these resources, shall be determined, and conduct shall not be authorized or approved that has or is likely to have such an effect if there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare. [MCL 324.1705(2)].

Before reaching the question of whether there is a feasible and prudent alternative to a permit applicant's conduct under Section 1705(2) of MEPA, the MDEQ is to determine whether the conduct has or is likely to have the effect of polluting, impairing, or destroying natural resources. If the MDEQ concludes the conduct has or is likely to have that effect, the conduct shall not be authorized if there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare. If, however, the MDEQ determines the applicant's conduct does not have or is not likely to have that effect, it is unnecessary to analyze whether a feasible and prudent alternative exists.

Not all environmental impacts from human activities pollute, impair, or destroy natural resources. As the Michigan Supreme Court has observed, "virtually all human activities can be found to adversely impact natural resources in some way or other. The real question before us is when does such impact rise to the level of impairment or destruction?"⁴ Whether the emissions from a facility rise to the level of pollution, impairment, or destruction of natural resources is determined based on the particular facts of the facility's operations and its impacts. The factors to examine include whether the natural resources involved are rare, unique, or endangered and whether the natural resources impacted are easily replaceable.⁵

³ See *Preserve the Dunes, Inc v MDEQ*, 471 Mich 508, 514; 684 NW2d 847 (2004).

⁴ *West Michigan Env'tl Action Council v Natural Resources Comm'n*, 405 Mich 741, 760; 275 NW2d 538 (1979).

⁵ *Nemeth v Abonmarche Development Inc*, 457 Mich 16, 31-36; 574 NW2d 641 (1998).

Climate change is caused by changes in atmospheric concentrations of GHGs and aerosols, as well as changes in land cover and solar radiation. Global emissions of GHGs from human activities have increased since pre-industrial times, with an increase of 70% from 1970 to 2004.⁶

According to the Intergovernmental Panel on Climate Change, CO₂ is the most important anthropogenic GHG. Annual emissions of CO₂ from global anthropogenic activities increased by approximately 80% between 1970 and 2004.⁷ Once GHGs (including CO₂) are emitted from anthropogenic activities anywhere around the world, they become well mixed globally in the atmosphere and remain in the atmosphere for decades to centuries.⁸

GHG emissions from the proposed facility will not rise to the level of pollution, impairment or destruction under MEPA. The available information indicates that the current and future adverse effects of climate change (such as more frequent heat waves, increased drought, sea level rise, and more intense storms) are very likely caused by GHG emissions from anthropogenic activities globally over the course of past decades and centuries.⁹ Adverse effects that are projected to occur in the future will not be caused by the GHGs emitted from the proposed facility. Since the incremental contribution to climate change from GHGs emitted by the facility does not have and is not likely to have the effect of polluting, impairing or destroying natural resources, no analysis of alternatives under MEPA is required.

Two commenters submitted a Petition to Intervene pursuant to Section 1705(1) of MEPA. Like the comments they submitted on the draft permit, they allege that GHGs from the facility will exacerbate climate change and that the MDEQ must deny the permit under Section 1705(a)(2). This response addresses the comments on the draft permit and the Petition to Intervene.

Comment:

MEPA requires the MDEQ to adopt more stringent pollution standards than those required by the CAA and Part 55 if Wolverines' actions have or are likely to have the effect of polluting, impairing, or destroying natural resources. Air pollutant emissions from the proposed facility -- even if they complied with the CAA and Part 55 -- will adversely impact public health, air quality, water quality and vegetation.

In addition, the facility will result in negative impacts from coal mining and associated transportation, water withdrawals, water discharges, and waste disposal. These impacts constitute pollution, impairment, or destruction of natural resources under MEPA.

Response:

The permit requirements developed pursuant to the CAA and Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (NREPA), to address air emissions are protective of public health and the environment. Air emissions from the facility do not constitute pollution, impairment, or destruction of natural resources under MEPA.

⁶ Intergovernmental Panel on Climate Change, Climate Change: 2007, Synthesis Report, Summary for Policy Makers, at 5 (Nov. 17, 2007).

⁷ See id.

⁸ 74 Fed Reg 18,886, 18,888 (April 24, 2009).

⁹ See IPCC Synthesis Report, at 5; 74 Fed Reg at 18,888.

Wolverine must comply with all applicable pollution standards regarding environmental media other than air. The commenters provide no information to show that the impacts to such other media will rise to the level of pollution, impairment, or destruction when the facility is operating pursuant to the applicable pollution standards. In addition, it is noted that some of the activities listed by the commenter (e.g. coal mining and the associated transportation) take place outside of the State of Michigan. MEPA would not apply to those activities.

Comment:

MEPA requires the MDEQ to thoroughly evaluate alternatives to the facility. If a permit is issued, MEPA requires that the emission limits not be based on the "worst case" fuels proposed by Wolverine. Instead, the emission limits must be based on less polluting alternatives (such as natural gas, biomass, and/or lower sulfur coals).

Response:

As stated previously, Section 1705(2) of MEPA provides that alternatives are evaluated in licensing proceedings if it is determined that the proposed conduct has or is likely to have the effect of polluting, impairing, or destroying natural resources. The facility will not have that effect. MEPA does not, therefore, require an evaluation of feasible and prudent alternatives.

Comment:

Rule 901 requires consideration of cleaner alternatives and limits on GHG emissions.

Response:

Rule 901 states:

- “Notwithstanding the provisions of any other department rule, a person shall not cause or permit the emission of an air contaminant or water vapor in quantities that cause, alone or in reaction with other air contaminants, either of the following:
- (a) Injurious effects to human health or safety, animal life, plant life or significant economic value, or property.
 - (b) Unreasonable interference with the comfortable enjoyment of life and property.”

The air contaminants emitted from the proposed facility, including GHG, will not have either of the effects identified in Rule 901. Wolverine is required to comply with the permit requirements developed pursuant to Part 55 and the CAA to ensure protection of public health and the environment. GHG emissions have been addressed under the BACT review and appropriate limits have been added to the permits. Additional information can be found under the BACT Section of this document.

Comment:

Section 165(a)(2) of the CAA, 42 USC 7475(a)(2), requires a thorough evaluation of the need for, and cleaner alternatives to, the proposed facility. That evaluation must consider environmental impacts from the facility, energy need, alternatives in addition to a no-build option, and measures to avoid or minimize environmental impacts (including impacts from GHG emissions).

In addition, Section 165(a)(2) provides authority to the MDEQ to deny a permit application based on the relative environmental impacts of the proposed facility and cleaner alternatives and to impose permit conditions beyond those required to satisfy BACT.

The available information demonstrates that the proposed facility is not needed. Whatever need exists can be met through the use of cleaner alternatives.

Response:

Section 165(a)(2) states that no major emitting facility may be constructed in an area that is in attainment with the NAAQS unless a public hearing has been held on the proposed permit and an opportunity provided for interested persons to submit presentations on the air quality impact of the source and "alternatives thereto."

The MDEQ has analyzed alternatives to the proposed facility pursuant to Section 165(a)(2), including less polluting alternatives. Alternatives to the facility are addressed elsewhere in this document.

Comment:

Section 165(a)(4) of the CAA, 42 USC 7475(a)(2), requires the consideration of collateral environmental impacts as part of step 4 of a BACT analysis.

Response:

The MDEQ analyzed collateral environmental impacts as part of its BACT analysis.

Comment:

The proposed facility will emit significant amounts of hazardous air pollutants. An evaluation of cleaner alternatives is therefore required under MEPA and Rule 901.

Response:

The permit restricts the emission of hazardous air pollutants pursuant to the requirements of Michigan's air toxics rules and the CAA to ensure they are protective of public health and the environment. The emissions that Wolverine is authorized to emit do not rise to the level of pollution, impairment or destruction of natural resources under MEPA, nor do they result in the effects listed in Rule 901.

Comment:

PM2.5 NAAQS is inadequate to protect public health and the environment. MEPA and Rule 901 require emissions limits beyond those needed to meet the PM2.5 NAAQS.

Response:

A PM2.5 NAAQS modeling analysis was performed taking into account all emissions at the proposed facility; along with other sources in the area expected to contribute to the NAAQS impact. Modeling demonstrated that emissions of PM2.5 comply with the NAAQS. The proposed facility's emissions do not cause or contribute to exceedence of the NAAQS for PM2.5 within the meaning of the Clean Air Act and Part 55.

This analysis demonstrates the PM2.5 emissions from the facility do not rise to the level of pollution, impairment, or destruction of natural resources under MEPA. It further demonstrates that the PM2.5 emissions do not result in the effects listed in Rule 901.

MDEQ relies upon the NAAQS for PM2.5 as the appropriate health protection benchmark for the assessment of the proposed facility. Attainment of the primary NAAQS is presumptively protective of the public health. On that basis, MDEQ has concluded that the emissions of PM from the proposed facility will not have an adverse impact on public health.

On December 18, 2006, EPA revised the NAAQS for PM2.5 to levels required to protect the public health with an adequate margin of safety. On February 24, 2009, the U.S. Court of Appeals for the District of Columbia Circuit granted a petition for review and remanded to EPA for reconsideration the primary annual NAAQS and the secondary NAAQS for PM2.5. The PM2.5 NAAQS were not vacated by the court, and the court did not find that the primary annual NAAQS was inadequately protective of the public health. The court found that EPA's failure to explain adequately why the primary annual level of 15 ug/m3 is sufficient to protect public health was in principle a curable defect. EPA is currently in the process of re-evaluating the PM2.5 NAAQS, as a matter of routine updating and assessment of the relevant studies and in response to the court's remand.

The MDEQ has not concluded that the PM2.5 NAAQS are inadequate standards for public health protection or that Rule 901 should be applied to require further reductions in allowable facility impacts of PM2.5. The PM2.5 emissions from the proposed facility do not cause the adverse effects listed in Rule 901 and do not rise to the level of pollution, impairment, or destruction of natural resources under MEPA.

Comment:

The emission of criteria air pollutants will pollute, impair and destroy natural resources. More specifically, negative impacts to human health from the emission of criteria pollutants may occur at levels below the NAAQS established by EPA as shown by the Senate Report that accompanied the 1977 amendments to the CAA. MEPA and Rule 901 therefore require an evaluation of cleaner alternatives.

Response:

The commenter mistakenly interpreted the Senate Report. The Senate Report emphasizes that the NAAQS are insufficient to protect public health and welfare and explains that Congress added the PSD program to the CAA in 1977 to achieve air quality better than the NAAQS. The permit for the proposed facility ensures that Wolverines' operations will meet the requirements of both the NAAQS and the PSD program. Further, in 1977 the Senate Report did not address PM2.5 emissions.

C. Public Health and Environment Concerns

Comment:

The Fact Sheet for the draft permit states: "Only a fraction of the mercury emitted may deposit locally. The remainder undergoes long-range transport where it disperses and may still deposit, but at lesser levels of impact than occurs locally." The statement shows an error in the assumptions MDEQ used to evaluate the risks from mercury emitted by the proposed facility. Recent studies (e.g., the Steubenville, Ohio study by Keeler et al.) have shown that the majority of mercury deposition occurs locally and is from coal plants. As a result, MDEQ's assumptions regarding local deposition are without foundation and contradicted by the most recent studies on the subject. MDEQ's flawed assumptions regarding local deposition underestimate the impact the proposed facility will have on local water bodies

and, in turn, the health impacts to local tribal populations dependent upon local water bodies for subsistence fishing.

Response:

The statement the commenter quotes from the Fact Sheet was intended to dispel any misconception that all of the emitted mercury will deposit in the local watersheds. While wet- and dry-weather deposition processes can be expected to cause some local mercury deposition (e.g., within a few kilometers of the source), most mercury emissions will travel greater distances and disperse over larger areas.

The MDEQ did not underestimate the risks from the facility's mercury emissions. To the contrary, the impact assessment used extremely conservative assumptions to overestimate the likely impact from the mercury emissions and analyze whether that overstated impact did not pose an unacceptable risk to public health or the environment. One of the assumptions concerned the extent to which the mercury emissions are deposited near the facility.

The local deposition impact of mercury air emissions is highly dependent on the form (speciation) of mercury. In its 1997 Mercury Study Report to Congress, EPA estimates that small, medium and large coal-fired boilers emit 50% elemental mercury, 30% divalent mercury vapor, and 20% divalent particle-bound mercury ("50:30:20" speciation profile). Local deposition of elemental mercury is expected to be negligible; it enters the "global cycle". Divalent mercury is expected to deposit in greater quantities closer to the emission source compared to elemental mercury. Divalent mercury vapor (also known as reactive gaseous mercury or "RGM") is expected to deposit closer to the source than divalent particle-bound mercury. The risk assessment performed for the proposed facility used the extremely conservative assumption that the mercury emissions consist of 100% RGM. In other words, the risk assessment used a worst-case approach regarding the form of mercury emitted to maximize the calculation regarding local deposition and ensure that such deposition was not understated. Based on the impacts using this and other conservative assumptions that overestimate the likely risks from the facility, the MDEQ nevertheless determined the mercury emissions from the facility are not anticipated to be harmful to the public health.

The assumptions in the impact assessment are not inconsistent with the findings of the Steubenville, Ohio study. That study evaluated mercury deposition at a monitoring station, rather than evaluating the dispersion and deposition pattern of mercury from any particular emission source. It does not identify the form of mercury emitted from regional coal-fired boilers or the fraction of emitted mercury from those boilers that deposited locally versus the fraction that did not. Here, the impact assessment used a worst-case approach to local deposition due to mercury speciation by assuming that 100% of the mercury emitted from the proposed facility is RGM.

Comment:

MDEQ only modeled deposition to four inland lakes. Deposition to Lake Huron was completely disregarded. MDEQ's assessment ignored both the degree to which Lake Huron would be impacted by the proposed coal plant and also the important role Lake Huron plays in tribal subsistence fishing. What criteria were used to evaluate the deposition radius for mercury since elemental mercury travels thousands of miles?

Response:

MDEQ determined it would be appropriate to conduct an assessment of the potential deposition impacts of the mercury emissions from the proposed Wolverine Power facility. The purpose of the mercury impact assessment is to characterize the potential long-term impacts to fish mercury levels in the lakes likely to be the most impacted and that may reasonably be assumed to have fish populations that can support recreational sport fishing. This is an appropriate approach. The most useful risk assessment approach is to characterize the incremental impacts from the facility's mercury emissions to the fisheries that are expected to be the most affected. If the risk assessment establishes that the incremental impact at the most affected fisheries does not pose an unacceptable risk to public health from eating fish, then the incremental impact at lesser affected fisheries will similarly not pose an unacceptable risk.

Selecting the fisheries most affected by mercury deposition from the proposed facility is guided by several key considerations. The proximity of the water body and watershed to the source is an important factor, since deposition rates are generally greater near the facility. The prevailing wind directions are also important, since varying wind directions determine the direction of movement of the mercury in the air emissions. The size (area) of the water body and watershed is another important factor to evaluate deposition impacts from the background concentration of mercury in the atmosphere and from the mercury emitted by the facility. Additionally, the background fish mercury level can be an important consideration when such data are available and show that the background fish mercury level is already approaching or exceeding a level of concern.

In the case of the mercury impact assessment for the proposed facility, the MDEQ determined that four nearby inland lakes to the east and southeast of the proposed facility could support recreational fisheries and would be the most impacted fisheries. The assessment estimated that the background fish mercury level is between 0.24 and 0.30 mg/kg at the four inland lakes (depending on the combination of assumptions used). The greatest incremental impact is 0.007 mg/kg at the most impacted water body (Swan Lake). The cumulative mercury level in fish at the most impacted water body is less than the fish advisory trigger level of 0.5 mg/kg and less than the value of 0.35 mg/kg the MDEQ uses to determine if waters are in attainment with the designated use of fish consumption under Part 31 of NREPA.

An assessment of Lake Huron would not be an appropriate focus for the study; because Lake Huron is expected have a lower incremental impact than the four selected lakes. Lake Huron is a very large body of water, with an area of approximately 59,600 km² and a drainage area of approximately 134,100 km². There is a significant background mercury atmospheric deposition loading in the region (approximately 14 to 19 ug per m² per year, which equates to approximately 6,000 to 8,000 lb/yr to the Lake Huron watershed). If all of the facility's permitted emissions of mercury (47 lb/yr) were conservatively assumed to deposit in the Lake Huron watershed, the incremental depositional impact would constitute only 0.6% to 0.8% of the background loading. Furthermore, the incremental impact of the facility relative to the background rate for Lake Huron is not reasonably expected to be as great as it is for the inland lakes near the source that were selected for the assessment. The potential impact of the facility's emissions to Lake Huron and other fisheries not included in the assessment will be no greater than the impact estimated for the four inland lakes included in the assessment. Lake Huron fish mercury levels are not currently elevated based on the MDEQ-Water Bureau designation of attainment status for surface waters. The commenter has not provided any information that would cause MDEQ to question the mercury impact assessment.

Comment:

MDEQ ignored all the data on subsistence fishing by tribes in Michigan and considered only much lower levels of fish consumption. The level of protection MDEQ incorporated in its modeling is not reflective of tribal subsistence fishing and is that of an angler who only eats one fish meal every two weeks. MDEQ thereby violated its Rule 228 requirements.

Response:

Rules 228 and 229(b) of Michigan's Air Pollution Control Rules authorize the MDEQ to conduct toxicological assessments using relevant scientific information to ensure the allowable mercury emissions from a proposed facility are protective of human health. The factors and variables the MDEQ uses in performing the assessments are based on the circumstances specific to the facility being evaluated.

With regard to fish consumption rate, EPA has considered the range of fish consumption rates from survey data, including data regarding "subsistence" fish consumption, and recommended using a rate of 15 g/day for the purposes of developing chemical-specific water quality standards and pollutant discharge limits for the Great Lakes region.¹⁰ EPA determined that this rate was reasonable and provided adequate protection, while acknowledging that some portion of the population will consume greater than 15 g/day. The consumption rate of 15 g/day is approximately the average rate for the subpopulation of regional sport anglers and their families for the consumption of regional sport-caught fish. This value also approximates the 90th percentile for the entire regional population.

Subsequently, the MDEQ Water Bureau promulgated Rule 1057 under Part 31 of NREPA which incorporates a fish consumption rate of 15 g/day for calculating human noncancer and cancer values to develop water quality standards and pollutant discharge limits. Rule 1057 also states: "Human health values may be modified on a site-specific basis to be more or less stringent to reflect local environmental conditions or local human exposure." This rule authorizes the use of a fish consumption rate other than 15 g/day based on site-specific information.

In this case, the four inland lakes evaluated in the mercury impact assessment are privately owned lakes. They have no public access. The commenter has not provided any site-specific information showing that these or other nearby lakes are used for tribal subsistence fishing. MDEQ determined that, for the four inland lakes that are the most impacted fisheries and evaluated in the mercury impact assessment, 15 g/day is an appropriate fish consumption rate for purposes of evaluating the impact of mercury deposition from the proposed facility.

The risk assessment provided estimates of a 0.24 to 0.3 ppm background mercury level in fish in the lakes evaluated, and an estimate of 0.001 to 0.007 ppm incremental impact due to the facility long-term deposition impacts. Thus, the incremental impact is approximately 0.3 to 3% of the background level. This estimate applies regardless of the assumed fish consumption rate. Therefore, if a person is assumed to consume fish at a higher (e.g., subsistence) rate, their mercury exposure would still be reasonably anticipated to be predominantly due to the background fish mercury level, not the incremental impact.

¹⁰ Water Quality Guidance for the Great Lakes System, 40 CFR Part 132.

Comment:

The cumulative risk assessment for the proposed facility does not meet the requirements of Rule 901, as it fails to follow guidelines recommended by EPA and the National Academies of Science and thus underestimates cumulative risk.

Response:

The cumulative risk assessment the MDEQ performed to evaluate non-cancer and cancer effects of emitted toxic air contaminants followed USEPA and MDEQ-AQD guidance. The MDEQ adopted a conservative approach in which all toxic air contaminants from the proposed facility with an impact equal to or greater than one percent of the relevant health based screening level were assumed to act additively. The MDEQ calculated the hazard quotient (HQ) for each such toxic air contaminant. The HQs for the noncarcinogenic toxic air contaminants were then summed to calculate a total hazard index. As a conservative screening-level step, the MDEQ calculated the total hazard index for noncarcinogens by summing the hazard quotients of all the individual air contaminants examined regardless of whether they impact the same organ or have the same effect.¹¹ Based on its analysis, the MDEQ correctly determined that the cumulative cancer and noncancer risks from the proposed facility do not pose an unacceptable risk to public health.

The commenters cited two different reports by the National Academies of Science (NAS). In the first of these ("Phthalates and Cumulative Risk Assessment: The Task Ahead"), the NAS recommended that cumulative risk assessment should evaluate exposures to combinations of substances which have the same toxic effects, regardless of whether or not their mechanisms of action have been shown to be the same. MDEQ agrees with that recommendation. In the particular case of the cumulative risk assessment for the proposed facility, MDEQ took an even more conservative approach for noncancer cumulative risk assessment by combining all substances additively, whether they had the same toxic effects or not. The second cited NAS report (Science and Decisions: Advancing Risk Assessment) provided general recommendations to EPA for ways to improve cumulative risk assessments in the future, while noting the complexity of considering many factors simultaneously and recognizing the need for simplified risk assessment tools for screening-level risk assessments. The MDEQ's cumulative risk assessment for the proposed facility was an appropriate screening-level approach utilizing current EPA guidance.

Additional information concerning the cumulative risk assessment is contained in the administrative record in the Human Health Risk Assessment Scope for the Wolverine Clean Energy Venture, dated August 11, 2008, and in the Addendum: Wolverine Clean Energy Venture (WCEV) Mercury Risk Assessment and Cumulative Risk Assessment, dated September 17, 2008.¹²

Comment:

The draft permit will allow significant emissions of carcinogenic toxics that pose an unacceptable cancer risk to Michigan residents.

¹¹ The hazard quotient (HQ) for a substance is calculated by dividing the maximum ambient air impact by the applicable health based screening level. A hazard quotient of less than one indicates that emissions of the toxic air contaminant are expected to be safe.

¹² As discussed in the Human Health Risk Assessment, the background level of air toxics in the area around the proposed facility is not significant. The background cumulative HI is less than one for respiratory and neurological effects based on the background level of air toxics in Presque Isle County.

Response:

The predicted emissions and ambient air impacts of all carcinogenic air toxics comply with the applicable health-based screening levels established pursuant to Michigan's Air Pollution Control Rules. There are no unacceptable cancer risks to Michigan residents associated with the proposed facility.

Comment:

Scientific consensus exists that serious health impacts from PM_{2.5} occur at levels below the current NAAQS. The MDEQ cannot rely on compliance with PM_{2.5} NAAQS to satisfy its Rule 901 obligations, as Rule 901 applies regardless of other regulations. Indeed, MDEQ required a Rule 901 analysis of lead, a criteria pollutant for which full PSD analysis may be required, even though the facility did not trigger PSD for lead. Also, MEPA requires a comparison of PM_{2.5} impacts to health protective levels, not the 2006 NAAQS which have been remanded to EPA. The health impact analysis did not include the existing incidences of cardiovascular and cardiopulmonary disorders present in area residents that increase risk from particulate matter emissions.

Response:

In 2006, EPA revised the NAAQS for particulate matter to levels required to protect the public health with an adequate margin of safety. As discussed elsewhere in this document, the ambient air near the proposed facility is in attainment with the PM_{2.5} NAAQS and would remain in attainment after conservative (i.e., high-end) potential impacts of the facility are taken into account.

In establishing the revised PM_{2.5} NAAQS, EPA considered many comments, including those from the Clean Air Scientific Advisory Committee (CASAC). Correspondence from CASAC to EPA (September 29, 2006) indicated agreement with the setting of the 24-hour NAAQS at a level of 35 ug/m³, but reiterated their recommendation that the annual primary PM_{2.5} NAAQS should be decreased from 15 ug/m³ to 13-14 ug/m³. The MDEQ has not concluded that the PM_{2.5} NAAQS are inadequate standards for public health protection or that Rule 901 should be applied to require further reductions in allowable facility impacts of PM_{2.5}. However, the potential impacts of the facility plus the impacts from other sources and background levels result in a maximum ambient air annual PM_{2.5} level of approximately 11 ug/m³. That concentration is below the CASAC recommended range of 13-14 ug/m³. Regardless of the applicability of Rule 901 or MEPA to PM_{2.5} emissions, the PM_{2.5} emissions from the proposed facility do not cause the adverse effects listed in Rule 901 and do not rise to the level of pollution, impairment, or destruction of natural resources under MEPA.

EPA is currently in the process of re-evaluating the PM NAAQS, as a matter of routine updating and assessment of the relevant studies and in response to the remand by the U.S. Court of Appeals for the D.C. Circuit. EPA is currently reevaluating the PM_{2.5} NAAQS. The MDEQ will ensure that future proposed facilities, like the facility proposed by Wolverine Power, do not cause or contribute to an exceedence of the NAAQS.

Comment:

The facility will be a source of pollutants that cause cancer, birth defects, and other serious health problems at low levels of exposure. It will also emit persistent toxic pollutants that will contaminate the environment and will increase health burdens and accompanying social and

economic burdens. The MDEQ's analysis estimates five cancer cases will be caused by the facility's operations, and that is too high.

Response:

The MDEQ did not estimate that five cancer cases will be caused by the facility's operations. In the air toxics cumulative cancer risk assessment, the MDEQ estimated a plausible upper bound cumulative inhalation cancer risk of approximately five in one million for hypothetical individuals located at the point of maximum ambient air impact continuously for 70 years. The emissions and impacts will comply with all applicable regulations that are designed to ensure an adequate level of protection for the environment and public health.

Comment:

The State should undertake a full analysis of the harm that may result from emissions from the proposed facility, including effects on the local population. The potential increase in harmful effects may occur across the State and in other areas where the emissions from the facility will travel have not been described or considered by the MDEQ. The MDEQ chose not to comprehensively evaluate the impacts of the proposed plant on Lake Huron or on many other water bodies in the region. The proposed permitted arsenic emissions could result in thousands of cancer cases, occurring over a period extending long into the future, based on the EPA cancer potency value and assuming there is no wasted dose. Arsenic emissions and modeling did not take into consideration existing arsenic contamination (including all sources of arsenic emission), assess adsorption rates, or incorporate new arsenic health effects information into an integrated source-receptor and exposure assessment.

Response:

The predicted emissions and ambient air impacts of air toxics comply with Michigan's Air Pollution Control Rules. The arsenic and other air toxics emissions are approvable because the maximum modeled ambient air impacts do not exceed the health protective screening levels established by the MDEQ. In addition, the cumulative risk assessment and mercury impact assessment further establish that the emissions are not anticipated to be harmful to public health.

The MDEQ analyzed the maximum ambient air impacts from the proposed facility and compared them to the applicable health based screening levels. The maximum modeled ambient air impacts occur relatively close to the proposed facility. At greater distances, the emissions are more dispersed, the ambient air impacts reduced, and the potential risks also meet the applicable requirements. The MDEQ's analysis demonstrates that the impacts at Lake Huron and other water bodies in the region meet the applicable screening levels. Similarly, the cumulative risk assessment and the mercury impact assessment show that the emissions from the proposed facility at all water bodies, including Lake Huron, do not pose an unacceptable risk.

With regard to arsenic, the MDEQ's analysis of carcinogenic air contaminants included an assessment of the cancer risks from inhaling arsenic emitted from the proposed facility. Based on the applicable requirements in Michigan's Air Pollution Control Rules, the analysis established there is not an unacceptable inhalation risk.

In addition, arsenic has a low potential for environmental accumulation through deposition and indirect pathways of exposure (such as children eating soil containing arsenic). EPA's

(1998) Utility Air Toxics Report to Congress included an assessment of the risks from deposition and indirect exposure pathways for air toxics emissions from 426 coal-fired utilities. The agency's analysis examined local and long-range impacts for individual facilities as well as cumulative impacts. For arsenic, EPA analyzed deposition and indirect exposure for four model facilities and found cancer risk estimates of 4 in 10 million to 1 in 10,000 (for the pica child, i.e., a child that is assumed to ingest significant quantities of soil). Background exposures were estimated to dominate the exposures and risks in all scenarios. The findings of the EPA study reinforce the MDEQ's conclusion that, due to the low risks to human health and the environment from deposition and indirect exposure to arsenic, a separate study to analyze the risks associated with arsenic deposition and indirect exposure was neither required nor appropriate. The commenters did not provide any specific information to show that such a study would alter the permit decision-making process.

Comment:

A full exposure assessment, taking into consideration susceptible populations and important natural resources, has not been adequately carried out, leading to substantial underestimation of the harm that would be caused. A comprehensive cumulative risk assessment of human health impacts was not performed. Examples of incomplete evaluation include mercury transport and bioaccumulation, soil and plant contamination, carcinogen contamination of waterways, high fish consumption rates, children with asthma and other respiratory disorders, elderly residents, cumulative neurological impacts, endocrine disruptors, and impacts to fisheries. The addition of ANY neurotoxic heavy metal is harmful to those women and their children with mercury levels posing health risks.

Response:

The MDEQ disagrees that the risk assessment was too narrowly focused. The MDEQ utilized health-based screening levels for air toxics, NAAQS for criteria pollutants, and a multi-pathway risk assessment for mercury and lead. The MDEQ also utilized U.S.EPA guidance for the cumulative risk assessment.

The MDEQ performed a cumulative risk assessment for both carcinogenic and noncarcinogenic toxic air contaminants. The scope of the assessment was broad and used conservative assumptions to ensure that the cumulative risks were not underestimated. Among other things, the MDEQ used the maximum ambient air impacts and calculated a total hazard index of noncarcinogenic toxic air contaminants regardless of whether they impact the same organ or have the same effect. Even with these extremely conservative assumptions, the MDEQ determined that the cumulative risks from the emission of toxic air contaminants do not pose an unacceptable risk to human health. The commenter has not provided any specific information to show the risk assessment underestimates the harm from the proposed facility.

Comment:

The coal ash can contain mercury and other heavy metals, and all landfills leak eventually. MDEQ has not addressed these concerns adequately. Our health and our children's health is at stake.

Response:

The regulatory review and permitting of Wolverine's potential disposal of coal ash in a landfill is not within the bounds of the MDEQ's assessment of the permit to install application for air emissions, and thus was not part of the review of this permit application.

Comment:

Minor or catastrophic system failures or human errors, and probabilistic risk, should have been assessed in order to account for potentially increased acute and chronic health risks and contamination of natural resources.

Response:

Part 55 and its rules do not require such assessment methods as part of the MDEQ's air toxics analysis. The permit requires Wolverine to implement a malfunction abatement plan to prevent, detect, and correct malfunctions or equipment failures resulting in emissions exceeding any applicable emissions limit.

Comment:

Using brominated compounds to control mercury emissions trades one carcinogen for another. The EPA took bromine off the market because Bromo-Seltzer killed people. The State of Michigan has not answered questions as to how much bromine is going in, how much is going in the landfill and how much is going in the air.

Response:

Bromine is a naturally occurring element, present in soils at a few ppm and in seawater at approximately 65 milligrams per liter. Bromine is used in the manufacture of many products. Although breathing high concentrations of bromine (e.g., 1 ppm) can be very irritating, bromine is less toxic than chlorine and the acceptable occupational exposure level is 0.1 ppm (approximately 654 micrograms per cubic meter).

Bromo-Seltzer was in a class of tranquilizers called bromides, which were used as a pain reliever and sedative for heartburn, upset stomach, or acid indigestion; they were withdrawn from the American market in 1975 due to their chronic toxicity. The therapeutic dose of bromide was reportedly about 3-5 grams, and repeated doses can accumulate because the body's elimination half-life is 9-12 days. Although occasional usage may have been safe, repeated doses as low as 0.5 -1 grams per day resulted in a risk of chronic toxic effects (neurological and gastrointestinal effects, and skin rash).

Neither bromine nor mercury are inhalation carcinogens. The use of activated carbon injection for mercury emission control by WCEV, which may potentially include brominated activated carbon, was considered by MDEQ and not found to pose a significant concern for potential bromine emissions. The majority of the bromine would be anticipated to remain bound in the activated carbon and appear in the flyash. Any bromine that may off-gas and appear in the air emissions would be expected to have a very low ambient air impact below that which could pose a threat of irritancy or other adverse effects.

Comment:

Presque Isle and surrounding counties have the highest per capita cancer rates in the State. It seems that most deaths in the area are caused by cancer. Information from the Detroit

News (detnews.com) indicates that the 2001-2005 cancer incidence rates per 100,000 people for Presque Isle County (512.9), Alpena County (499.7) and Montmorency County (565.9) are higher than the Michigan rate of 499.4 or the U.S. overall rate of 468.2.

Response:

Nationally, about 1 in 3 people will have cancer in their lifetime, therefore, cancer incidence rates appear to be high to citizens everywhere. The cancer incidence statistics provided by the commenter indicates that the source of the data was the National Cancer Institute (NCI). The NCI website (<http://www.cancer.gov/statistics>) provides cancer incidence statistics for each state, but not for individual counties. Therefore, the data presented by the Detroit News cannot be readily evaluated using the NCI website. However, the cancer statistics for each county in Michigan are available at the Michigan Department of Community Health (MDCH) website (www.michigan.gov/mdch; select "Statistics and Reports"), and these data are somewhat more recent than the NCI data cited by the Detroit News. MDEQ asked MDCH to review the data. They reported that the 1985 – 2007 cancer incidence rates for Presque Isle and Alpena Counties fluctuate above and below the State rate and do not indicate higher mortality than the State rate. The Montmorency County cancer incidence rate has been higher than the State rate fairly consistently, for reasons that are not understood but which may involve reporting problems.

The WCEV project emissions were evaluated for potential lifetime cumulative cancer risk. The point of maximum ambient air impact from the emissions was associated with a potential risk level of 5 in one million over a lifetime of continuous exposure. This is not considered to be an unacceptable incremental cancer risk under Part 55 of NREPA.

Comment:

What are the mercury deposition estimates for Swan Lake and the Swan River downstream? Is bioaccumulation considered?

Response:

The MDEQ evaluated mercury deposition and bioaccumulation impact to the Swan Lake watershed, resulting in facility deposition impact estimates of 0.22 grams per year to the lake and 9.06 grams per year to the watershed. The modeling also utilized an estimated background (not due to the facility) deposition rate of 6.53 grams per year to the lake and 591.79 grams per year to the watershed.

Comment:

Has the shifting wind direction from onshore to offshore been accounted for in the fallout pattern?

Response:

The air dispersion and impact assessment utilized meteorological data that accounted for all conditions of wind direction, and the mercury deposition impact assessment was based on the dispersion modeling results.

Comment:

How will calm wind conditions and calm wind precipitation events affect the fallout pattern from the stack plume?

Response:

Horizontal dispersion is slowed by calm wind conditions. Precipitation acts to strip many contaminants out of the air and deposit them.

Comment:

Concerning mercury deposition locally and downwind, why aren't ranges used instead of averages?

Response:

Long-term accumulated mercury deposition impacts are the focus of the risk assessment, because mercury is persistent and bioaccumulative and has cumulative impacts within watersheds. Therefore, the MDEQ analyzed the impacts on water bodies and watersheds based on three years of meteorological data. It is unclear what additional useful information, if any, would be gained by utilizing ranges of impacts over time or spatial dimensions.

Comment:

The revised permit application dated January 10, 2008, states on page 7-4: "The MMREM results conservatively indicate that the mercury concentrations in fish fillets from mature fish could increase from 0.83% to 1.25% in the target lakes." That is a 50.6% increase. Also, what happened to that forecast in the September 12, 2008 revision of the Rule 228 Analysis for Mercury Emissions?

Response:

As stated in the revised permit application, the range of estimated increases in mercury concentration in fish fillets is the estimated incremental increase in fish fillets due to mercury emitted from the proposed facility alone. Contrary to the commenters' suggestion, the percentage difference between the upper and lower end of that range (50.6%) does not represent the total increase in mercury concentration in fish fillets. The final revision to the risk assessment (September 12, 2008) included updated meteorological data (2005-2007) and a corrected mercury emission rate. For the four lakes evaluated, the final revision identifies an incremental increase of between 0.83% and 1.67% of the estimated background fish mercury level of 0.24 mg/kg.

Comment:

Michigan does not have a baseline of amounts of mercury in the environment; fish data are inadequate and much is missing. Mercury removed from coal burning emissions is only moved to other places.

Response:

Although there are gaps in the available fish mercury data, there is a substantial amount of environmental mercury information available that the MDEQ has compiled in several reports. For example, data on fish contaminant monitoring, including mercury, are compiled in MDEQ annual reports (http://www.michigan.gov/deq/0,1607,7-135-3313_3686_3728-32393--_00.html), and form the basis for fish consumption advisories from the Michigan Department of Community Health (http://www.michigan.gov/mdch/0,1607,7-132-54783_54784_54785---_00.html). The MDEQ Mercury Strategy Staff Report is available at

<http://www.michigan.gov/deq/0,1607,7-135--184041--,00.html>. Since mercury is an element, it cannot be destroyed. However, capturing and removing it from air emissions for disposal is an effective method for preventing release to the environment.

Comment:

The mercury impact assessment uses incorrect average surrogate fish values of 0.24 ppm (for Lake Esau) and 0.30 ppm (for Grand Lake). Fish mercury data exist for Swan Lake and Swan River (1986 chinook data) that indicate higher levels than those in the surrogate lakes (6/10 fish were 0.5 ppm or above). Also, the mercury assessment did not include many other lakes in the area.

In addition, the mercury impact assessment underestimated the local deposition of mercury. The Hubbard Brook Research Foundation of New Hampshire says that the average coal burning power plant has 40% reactive gaseous mercury, while the mercury assessment assumed 100% or 30%. DEQ assumed a dry deposition rate equivalent to the wet deposition rate, while the Hubbard Brook Research Foundation states that northeastern states have dry deposition ranging from 50% to 70% in forested areas.

Further, using data from Pellston for background atmospheric deposition of mercury is questionable because Pellston is in western Michigan while Rogers City is in eastern Michigan, which could affect the wet / dry patterns. It is also questionable why MDEQ suggested the use of a background deposition rate of 17.2 micrograms per square meter on land and water, while also modeling with an assumption of a significantly higher background deposition rate on land. Some other alternative combinations of modeling assumptions could have been used but were not, which would have more appropriately been worst-case.

Response:

The MDEQ did not use incorrect surrogate fish mercury values. Staff provided to the commenter the available fish mercury data for Lake Huron and inland waters. Included in that database were the 1986 Swan River Chinook salmon data (n = 10, arithmetic average = 0.447 ppm). Those fish were not resident to Swan Lake, but were collected in the fall of the year in Swan River. More recent Chinook salmon mercury data for Lake Huron indicate average levels of about 0.1 to 0.2 ppm, although the data have not been compiled for easy accessibility. The Lake Huron fish mercury data indicate attainment with all designated uses, according to MDEQ-Water Resources Division, i.e., they do not trigger nonattainment status designation under the Clean Water Act. The mercury risk assessment was appropriate and sufficient to demonstrate that the potential facility impacts would be acceptably low and are permissible.

Comment:

Are existing contaminants of concern and criteria pollutants in soils in the community considered in the assessment and how?

Response:

In the case of lead, the risk assessment used a multipathway approach. This included estimates of exposure due to existing (background) levels of lead in topsoil, among other exposure pathways.

Comment:

Neither the applicant nor the MDEQ has modeled how many people will die, be hospitalized, require emergency room care or will become sick because of this new facility. The modeling does not reflect the real consequence of issuing a permit to this facility, which will be increased hospitalizations and decreased quality of life.

Response:

The regulatory requirements of the permitting process ensure public health protection. The requirements include meeting the National Ambient Air Quality Standards and maximum allowable increases for criteria air pollutants, and satisfying the MDEQ air toxics rules for toxic air pollutants. These requirements are designed to safeguard the public health. Further, the extensive risk assessments that have been performed demonstrate that the emissions from the proposed facility do not pose an unacceptable risk to the public health. In addition, the commenter has not provided any modeling to suggest that emissions from the proposed facility pose an unacceptable risk.

Comment:

This particular shoreline is known for being home to a number of species protected by the Endangered Species Act. Any environmental impact study must determine how protected species will be impacted by any disruption of their habitat.

Response:

There is no regulatory requirement for that type of assessment. The Endangered Species Act is implemented at the federal government. In the case of Michigan's air permit program, Michigan is operating under an approved State Implementation Plan, which does not incorporate a review under the Endangered Species Act.

Comment:

MDEQ has not taken the economic burden and health burden of the people now and into the future into equal consideration.

Response:

MDEQ has accounted for public health concerns associated with the potential future operation of the facility. Part 55 and the Clean Air Act do not require an analysis of the economic effects of the proposed facility.

Comment:

Pollution from coal fired power plants in Michigan has a deadly health effect on Michigan citizens. It is forecast that pollution from Michigan coal plants will be responsible for the following health impacts in the state in the year 2010 alone: 981 deaths, 1000 hospital admissions, 1700 heart attacks, 700 cases of chronic bronchitis, 115 lung cancer deaths, 1500 emergency room visits, hundreds of thousands of lost work and school days, impacting the productivity of the state. Wolverine proposes to add particle pollution, SO₂ and NO_x pollution for the next 50 years. Allowing this additional pollution from the Wolverine plant will worsen the health threat already posed by pollution from coal plants and other sources in the state.

Response:

The commenter describes estimates of health impacts throughout the state that may be associated with criteria pollutant emissions from existing coal-fired power plants rather than the proposed facility. The MDEQ analyzed the public health impacts of criteria pollutant emissions from the proposed facility alone and in combination with the existing air contaminants in the atmosphere and determined that the facility's emissions meet all applicable federal and state requirements, including those designed to protect the public health.

The MDEQ has confidence that the extensive regulatory requirements of the permitting process ensure sufficient public health protection. These requirements include the NAAQS for criteria pollutants and the MDEQ air toxics rules for the toxic air pollutants, both of which are designed to provide sufficient public health safeguards. The risk assessments that have been performed for the facility's emissions do not suggest a significant public health threat.

Comment:

The proposed plant's warm water discharge and pollutants would affect water quality, fish, and aquatic species and habitats of Michigan's waters.

Response:

These concerns are not part of the MDEQ review of the permit to install application for air emissions. They are addressed as part of Wolverine's permitting process for surface water discharge.

Comment:

Michigan's mercury standards in fish have not been modernized. The federal EPA and FDA have set trigger levels of 0.3 ppm. Minnesota, Maine, and Canada have set levels of 0.2 ppm. Michigan trails at a much less sensitive trigger level for mercury in fish. The MDCH advisory trigger levels are only protective for sport fishermen. The new May 2007 protocol for uniform Great Lakes Sport Fish Consumption Advisory limits start at 0.058 ppm and advise no consumption at 0.95 ppm.

Response:

The mercury impact assessment cited both the MDEQ fish mercury value for determining attainment with water quality standards (0.35 mg/kg), and the Michigan Department of Community Health consumption advisory trigger level (0.5 mg/kg). The MDEQ value of 0.35 mg/kg is current. The MDCH is in the process of re-evaluating their fish consumption advisory trigger levels, but changes have not been made. The mercury impact assessment demonstrates that mercury level in fish fillets at the location of greatest impact is below both the MDEQ and MDCH levels. Mercury emissions from the proposed facility do not pose an unacceptable risk to public health.

Comment:

The modeling for mercury impact builds on a mathematical base of three lakes, all with no fish mercury data. The surrogate figure from Lake Esau is 0.24 ppm. This number is not an average or median of the Lake Esau data. Where did it come from?

Response:

The sample of ten smallmouth bass from Lake Esau in 2003 had a mean mercury concentration of 0.207 mg/kg with a 95% upper confidence limit (UCL) of 0.24 mg/kg. The 95% UCL value was used preferentially as a surrogate value for the lakes of interest in the evaluation, rather than the mean, in order to better ensure that the actual levels in the lakes of interest would not be underestimated. This step adds conservatism to the mercury incremental impact assessment for the lakes of interest (i.e., it results in higher estimates of the potential impact of the Wolverine Power mercury emissions than would be derived if the mean value were used).

Comment:

The application and risk assessment materials make no mention of Naturally Occurring Radioactive Material (NORM), which could be present in the coke, and could occur at levels harmful to human health, particularly for workers at the proposed facility.

Response:

There was no evidence of any amount of radium in the fuel sampling analysis done for petcoke.

Comment:

The T-BACT analysis under Rule 224 and Rule 225's health-based TAC screening analysis for the Draft Permit are inadequate to demonstrate protection of public health because they rely on AP-42 emission factors and are not clearly based on the contents of petroleum coke that will be burned at the facility.

Response:

MDEQ disagrees with the commenter. A health-based TAC analysis (R 336.1225) was performed and based on data used in AP-42, FIRE and from the Louisiana Cleco Corporation application, in which the facility was permitted to burn 100% petcoke. FIRE does not contain any emission factors for boilers firing pet coke, therefore the Cleco emission factors, which were greater than the FIRE emission factors for coal, were used to be conservative in the TAC analysis. Emission limits were added to the permit for those TACs that did not initially meet the recommended health based screening levels. The requirement for T-BACT (R 336.1224(1)) did not apply to this project because the project was subject to 112(g) MACT review (R 336.1224(2)).

Comment:

Can Wolverine assure local citizens that the clean water and air will be kept clean during the power plants lifetime?

Response:

There were no unacceptable concerns identified during the review of the application for this project. Worst case emissions were assessed and predicted impacts were below regulatory threshold levels.

This permit is limited to the activities at the source as they pertain to air emissions. Therefore, water related impacts were not evaluated in this permit application.

Comment:

The permit conditions do not specify fuel quality and testing requirements. In particular, trace metals and other hazardous chemicals in coke are highly variable, depending on what type of crude the coke came from. Thus, the health risk analyses for mercury, lead and other contaminants are inherently flawed, since they do not assume the full range of possible contaminants in the coke. At a minimum, coke should be analyzed prior to shipment, to ensure that contaminant levels are not above those assumed in the risk assessment. It is not protective of human health and the environment to rely on “end of pipe” metrics for these dangerous contaminants.

Response:

Special condition VI.12 of FGCFB requires the permittee to maintain records of fuel analysis.

1. Comments on Environmental Justice Concerns

Comment:

In 2007, Governor Granholm signed Executive Directive No. 2007-23, “Promoting Environmental Justice” (EJ Directive). The EJ Directive calls upon the MDEQ to develop and implement an environmental justice plan for Michigan, with the goals of identifying and preventing discriminatory public health and environmental effects of state laws, regulations, policies, and activities. Permitting of the proposed facility will have disproportionately harmful impacts on tribal public health and the environment. As such, MDEQ’s permitting action under state laws and regulations should have considered the differing and disproportionate impacts on tribes but it did not.

In particular, the Human Health Risk Assessment (HHRA) did not evaluate the impacts of mercury and other emissions from the proposed facility on subsistence fishers. Subsistence fishing is a reality of tribal life and prevalent in tribal communities. The MDEQ failed to consider the disproportionate impact on subsistence fishers in tribal communities. In addition to increased pollution to waters where tribal members fish, other expected impacts include increased pollution affecting plant species of importance to tribes and particulate matter impacts on air quality disproportionately impacting on tribe members’ health.

Response:

The applicable legal requirements were applied equally to all groups. The extent and scope of the risk assessment was consistent with the environmental justice principle of preventing disparate adverse impacts to protected groups. The MDEQ applied a greatly expanded public outreach, education and comment process for this permit application consistent with the environmental justice principle of providing opportunities for enhanced public participation.

With regard to methylmercury exposure via local fish consumption, concerns for higher rates of local fish consumption, including subsistence fishing, were also addressed in the risk assessment because the characterization of the incremental impact to fish mercury levels is applicable to any fish consumption rate. This is discussed in more detail in response to a comment regarding mercury emission and exposure concerns.

Comment:

Is the applicant required to conduct an Environmental Justice analysis? Is there state or federal law requiring an Environmental Justice analysis by the applicant?

Response:

There is no requirement for the applicant to perform an environmental justice analysis. The Air Quality Division strives to protect the health and welfare of all citizens of the State of Michigan equally. In addition, the state and federal air quality standards that have been established are designed to be protective for all segments of society, including the most sensitive. Therefore, the Air Quality Division has not attempted to determine the economic or racial demographics of the area, but has determined that the permit, as approved, will meet all applicable air quality standards.

Comment:

The State's Environmental Justice Plan that was finalized in December 2010 includes the use of the EPA's Strategic Enforcement Adjustment Tool (EJSEAT). EJSEAT uses 18 criteria to rank census tracts on a scale of 1 to 10, with a ranking of 1-3 indicating a relatively high priority for evaluation of environmental justice concerns. Rogers City has a ranking of "4", and the Rogers City area will unnecessarily be pushed over the edge into a high priority area of concern for public health if WCEV is approved and constructed.

Response:

The MDEQ's "Environmental Justice Plan" was finalized on Dec. 17, 2010 (http://www.michigan.gov/deq/0,1607,7-135-3306_51662---,00.html). The Plan presents the EPA's EJSEAT method as a screening approach to identify "potential environmental justice areas of concern". The report (page 9) states that for projects that require public outreach, enhanced public outreach activities will be implemented when the proposed project is located within one mile of a level 1, 2, or 3 potential environmental justice area of concern as identified by EPA's EJSEAT method. A map of Michigan showing the EJSEAT ranking of areas is provided in Attachment 6 of the report. The WCEV facility and the impacted area evaluated in the risk assessment are in EJSEAT priority areas 4 and 7. Therefore, this area is not currently located in a potential EJ area of concern, and the commenter did not provide any specific information to show that the WCEV facility would result in a higher ranking in the EJSEAT scoring system. Even if it could be assumed that the WCEV operation could result in an increase in the area's EJSEAT ranking, the ranking is only a screening approach to identify potential environmental justice areas of concern, not for determining when and where disparate impacts exist. An EJSEAT ranking of 1-3 would indicate a priority area for employing enhanced public outreach activities and for providing assurance that adverse disparate impacts would not occur. Regardless of the EJSEAT ranking of the WCEV area, the MDEQ has applied heightened public outreach efforts and conducted an extensive risk characterization to ensure that the facility will not have adverse public health impacts, consistent with EJ principles.

Comment:

The proposed facility would generate significant amounts of particulate matter, most notably PM2.5, which will impose an unwarranted and unacceptable health burden on the tribal communities in the vicinity. Pollutants that trigger asthma attacks impose a disproportionate burden on tribal communities. According to the Centers for Disease Control, the asthma rate among Native Americans is more than 50% higher than the rate among the rest of the

population. According to the study, published in Morbidity and Mortality Weekly Report, based on a 2002 survey, 11.6% of Native Americans said they suffered from asthma. This was significantly higher than the national average of 7.5%, and much higher than every other single racial or ethnic group. The draft permit, permit supporting materials, and application contain no consideration of the differing and unequal public health impact that tribal communities would bear as a result of the particulate matter pollution from the plant.

Response:

MDEQ has obtained and reviewed the study report that was apparently described by the commenter (<http://www.cdc.gov/mmwr/preview/mmwrhtml/mm5307a1.htm>). MDEQ relies upon the NAAQS for PM as the appropriate health protection benchmark for the assessment of the proposed facility. Attainment of the primary NAAQS is presumptively protective of the public health. On that basis, MDEQ has concluded that the emissions of PM from the proposed facility will not have an adverse impact on public health, including asthma prevalence among Native Americans. We are not aware of any other specific information that the facility emissions would aggravate asthma in the community.

D. Dispersion Modeling

Comment:

MDEQ violated the Clean Air Act by granting a waiver of preconstruction monitoring requirements. The Act requires that preconstruction monitoring be conducted specifically for the purpose of PSD permitting and does not allow monitoring data gathered for a different purpose to be substituted. Waiver of on-site preconstruction monitoring is unjustified when Wolverine has stated its intent to conduct on-site monitoring for PM10 and PM2.5. In addition, the existing, off-site monitoring data is not representative of the air quality in the area of the proposed project based on monitor location, quality of the data, and currentness of the data.

Response:

Part 55, the Act and their regulations do not require the use of on-site preconstruction ambient air quality data gathered for the sole purpose of determining whether the proposed facility will exceed the NAAQS or PSD increments. 40 CFR part 51, appendix W provides that regional site monitors may be used to determine background concentrations near an isolated single source (such as the proposed facility) if there are no monitors located in the vicinity of the facility and additional requirements are satisfied. Rule 299(2)(d) of the Michigan Air Pollution Control Rules adopts by reference the standards in 40 CFR part 51, appendix W.

The commenters seek to invalidate these provisions in 40 CFR part 51, appendix W. A challenge to a nationally applicable regulation must be filed in the U.S. Court of Appeals for the District of Columbia, not in this permit proceeding. The MDEQ does not have the authority to invalidate 40 CFR Part 51, appendix W.

On July 27, 2007, the MDEQ granted Wolverine's request for a waiver from on-site preconstruction monitoring and approved the use monitoring data for sulfur dioxide, carbon monoxide, nitrogen dioxide, PM10 and PM2.5. Wolverine proposed to perform on-site monitoring for PM10 and PM2.5 and requested the use of regional monitoring data to provide information for PM10 and PM2.5 in case of problems with the onsite monitoring it elected to perform. As discussed in a separate response, Wolverine did not complete its monitoring for

PM10 and PM2.5 due to technical problems and budgetary reasons. Regional site monitors may be used if, among other things, there are no monitors located in the vicinity of the source, regardless of an applicant's intent to perform on-site monitoring.

The MDEQ granted Wolverine's waiver request because the regional monitoring data are representative of the ambient air quality in the vicinity of the proposed facility. The MDEQ considered monitor location, quality of the data, and currentness of the data in granting the waiver request.

Data from regional monitor locations are sufficient to be substituted for site-specific data when 1) the data are representative of the subject area (i.e., the location(s) of maximum concentration increase from the proposed facility, the location(s) of the maximum air pollutant concentration from existing sources, and the location(s) of maximum pollutant concentration based on existing sources and the proposed facility), or 2) are likely more conservative than the subject area because it was collected in an area prone to higher concentrations (i.e., urban areas).

The ambient air quality monitor located in Missaukee County collected data for SO₂ and CO from 2002 through 2003 and NO₂ data during 2000. This data is representative of the subject area in Rogers City because prevailing southwest winds transport similar regional background concentrations to Rogers City. Data for SO₂ and CO collected in 2005 from a monitor located at the Seney National Wildlife Refuge (a rural location at a near latitude and upwind of the proposed facility) demonstrate that the Missaukee County data are representative of, or more conservative than, the ambient air quality of the subject area.

Although only one year of monitoring data is required, it is MDEQ's preferred practice to review the most recent three years of data from the most representative monitor and use the most conservative value recorded from that monitoring location as representative of the regional background. In rare cases, the most representative data may come from a monitor that has been recently decommissioned. If the most recent data from that monitor are not within the most recent 3-year window but are more likely to be representative than existing monitors from other locations, the older data may be considered for use. The factors to consider include: 1) whether any new significant sources of emissions have been added since the monitor was decommissioned, and 2) whether existing monitors from other locations, during the same period, show that those monitors are less representative than the recently decommissioned monitor. Both factors are satisfied in this case. Data from Missaukee County were therefore used in the determination of SO₂, NO₂, and CO background concentrations.

In addition, data for NO₂ collected during 2005 and 2006 from a monitor in Two Rivers, Wisconsin (also a rural, upwind location at a near latitude) confirmed that the Missaukee County NO₂ data are both current and conservative. The NO₂ data from the Two Rivers monitor shows a lower average annual NO₂ concentration than the Missaukee County data. Data for PM10 collected from a monitor in Flint (an upwind urban location) may be substituted for site specific data because they are likely more conservative than the subject area. The data were collected in 2004, 2005, and 2006, and were therefore current when the MDEQ granted Wolverine's waiver request.

The data from the regional monitors were collected pursuant to EPA's Ambient Monitoring Guidelines for PSD. Determination of background data for PM_{2.5} is discussed in a separate response.

MDEQ disagrees that data from the existing monitoring network cannot be considered as representative.

Comment:

The modeling analysis uses inappropriate meteorological data lacking the characteristics, detail and quality assurance required for modern modeling applications. The reliance on data from the Presque Isle airstrip is unacceptable for air dispersion modeling because it is not site specific and omits periods of calm.

Response:

The MDEQ allowed the applicant to use meteorology data from the National Weather Service (NWS) collection monitor at the Presque Isle County airport. This NWS monitor site is located within one mile of the proposed facility and resides within the near-field AERMOD modeling grid. Therefore, MDEQ disagrees with the commenters that this data should not be considered as "on-site" data. EPA guidance allows an applicant to use as little as one year of on-site meteorology data for required modeling demonstrations. However, MDEQ requested the applicant use all three years of available data from this monitoring site to increase the reliability of predicted impacts.

The commenters suggest that observational data collected at NWS sites are inadequate due to instrument exposure, location, and resolution and, thus, should not be used for air quality modeling studies. The siting criteria for instrument exposure, resolution, and accuracy are required to adhere to the standards outlined in the Federal Meteorological Handbook No. 1. The observational data collected from NWS stations contain necessary information that is routinely used in modeling, climate evaluations and real time meteorological conditions for the aviation industry. The collected data are input into complex NWS numerical forecast models which serve as a tool for the development of daily weather forecasts and are accurate and reliable.

The commenters state that aircraft takeoff and landings alter the reliability of the airstrip data. MDEQ disagrees as this airport is comprised of a single, seldom-used runway used by small, non-commercial aircraft. The infrequent landings, takeoffs and idling by such aircraft do not result in the data being unrepresentative of the area surrounding the proposed facility.

The commenters also state that NWS data are inadequate for air dispersion modeling purposes. Part of the commenter's rationale stems from the fact that reported NWS hourly data at the Presque Isle airstrip are derived from 2-minute averages taken within the last 10-minutes of every hour rather than a complete hourly average. This practice provides a "snapshot" image of the atmosphere for diagnostic forecasting and aviation purposes. 40 CFR part 51 appendix W, (the Guideline on Air Quality Models) authorizes the use of such data from NWS reporting stations (Section 8.3.1.2). Appendix W has been adopted by reference in Rule 299(2)(d) of the Michigan Air Pollution Control Rules.

The commenters also refer to the number of "calm" wind conditions contained within the NWS data as justification for invalidating modeling results. While it is true that when the NWS monitoring network was converted to the Automated Surface Observing System (ASOS) in the mid-1990's, they revised the definition of "calm" as wind speeds less than 3 knots. This policy decision resulted in annual data sets containing more reported calm hours than when data were manually collected. With this knowledge, EPA's AERMOD

Implementation Work Group (AIWG) performed a study to determine if the increased frequency of calm winds in the ASOS data significantly altered the outcome of modeled impacts. The results of this analysis were introduced during a national EPA modeler's workshop (Denver, June 10-12, 2008). The conclusion of the AIWG workgroup was that any perceived shortcomings of the data did not result in any unacceptable bias, and the use of standard ASOS data was acceptable for air dispersion modeling purposes. As a result, MDEQ disagrees that any additional on-site meteorological monitoring is required.

Comment:

The Applicant and MDEQ relied on illegal and dated draft thresholds to avoid a full Class I increment analysis.

Response:

Wolverine must demonstrate that emissions from the proposed facility will not cause or contribute to air pollution in excess of a PSD increment. Not all emissions cause or contribute to an exceedance. Insignificant, i.e., de minimis, emissions are permissible. The courts have determined that the permitting authority has discretionary authority under the Clean Air Act to exempt de minimis circumstances from review when the burdens of regulation yield a gain of trivial or no value.

MDEQ has determined that emissions from the proposed facility will not cause or contribute to an exceedance of a PSD increment or NAAQS if they are below the Class I significant impact levels (SILs) proposed by EPA in 1996. The SILs are numerical values that represent thresholds of insignificant impacts from the proposed facility. Sources whose contributions to ambient concentrations in Class I areas are below such de minimis levels do not cause or contribute to a PSD increment exceedance, do not have a significant impact, and are not required to perform a comprehensive PSD increment analysis. A full Class I air quality analysis is not required when impacts are less than the applicable SILs.

Comment:

A full increment analysis is likely to show violations of, among other things, the Class I 24-hour SO₂ increment.

Response:

As discussed in response to the previous comment, an impact does not cause or contribute to an increment violation if the impact is less than the applicable SIL. Additional factors also make it exceedingly unlikely that proposed SO₂ emissions from the proposed facility will cause an increment violation to a Class I area.

First, southeast winds would be needed to transport Wolverine emissions to Seney. Statistical wind roses from the Presque Isle County Airport show that winds from this direction are among the lowest percentage winds traveling over the Rogers City area.

Second, all Class I impact analyses and addendums were provided to the Federal Land Manager for review and approval. The Federal Land Manager for this project, Ms. Jill Webster (U.S. Fish and Wildlife Service) agreed that no violations are likely to occur: "A Class I modeling analysis was performed in support of the Prevention of Significant Deterioration (PSD) application submitted by Wolverine. This analysis assessed the impact to the Seney NWR due to the project. We have reviewed this modeling analysis and the

PSD application. Based on the information provided to us, we do not believe that the project will adversely impact visibility or air quality related values at Seney.” (e-mail from Jill Webster (USFWS) to William Campbell, ENSR, April 11, 2008). As such, MDEQ disagrees that a Class I increment violation is likely to occur.

Comment:

The Federal Land Manager failed to fully evaluate impacts on AQRVs.

Response:

The applicant is responsible for providing the appropriate Federal Land Manager with all air quality and visibility impact analyses for review and approval. Copies of the original permit application, visibility analyses, and all subsequent addendums pertaining to Class I impacts were provided to the Federal Land Manager agent, Ms. Jill Webster of the U.S. Fish and Wildlife Service. As discussed in the previous comment response, Ms. Webster approved all analyses and agreed that no violations are likely to occur: “A Class I modeling analysis was performed in support of the Prevention of Significant Deterioration (PSD) application submitted by Wolverine. This analysis assessed the impact to the Seney NWR due to the project. We have reviewed this modeling analysis and the PSD application. Based on the information provided to us, we do not believe that the project will adversely impact visibility or air quality related values at Seney.” (e-mail from Jill Webster (USFWS) to William Campbell, ENSR, April 11, 2008)

While MDEQ was not responsible for approving this portion of the analysis, the agency was provided with copies of the correspondence between the applicant and the Federal Land Manager.

Comment:

Class II NAAQS and Increments – SO₂, NO₂, VOC, PM₁₀; The modeling fails to take into account the impact of the quarry’s west wall on modeled concentrations.

Response:

The AERMOD modeling demonstration for all pollutants included terrain heights at all receptors. As such, the modeling did not fail to take into account the terrain heights along the quarry west wall.

Additionally, the CFB boiler 450 stack height of 450 feet is significantly higher than the 50-80 foot high west wall of the quarry. As such, it is unlikely that the west wall would have any accumulating or channeling effect upon the buoyant plume, even during light wind episodes. Any such effect was taken into account in the modeling by including terrain heights with each receptor.

Comment:

The modeling fails to measure total impacts from the quarry, proposed coal plant and other sources at receptors located on quarry property owned by Oglebay-Norton.

Response:

The air over secured property is considered “non-ambient” relative to that facility’s emissions and is excluded during the modeling analysis. As such, a separate run was made for “quarry only emissions” which excluded the receptors within the quarry’s airspace as non-ambient

but included all ambient receptors outside of the quarry airspace. The impacts from quarry emissions on receptors within the quarry's secured property were therefore correctly excluded from the modeling analysis. The analysis of impacts from non-quarry sources (i.e., Wolverine plus non-quarry offsite sources) correctly considered the quarry airspace as ambient air and included receptor impacts within the quarry airspace. To determine an overall impact from all sources, the maximum impacts from each of the runs were added together, regardless of the time and location of each run's maximum impact. By adding the maximum impacts from multiple modeling runs, this approach is more protective of air quality than a single run that merges all emissions together.

It would have been difficult, but technically possible, to merge the two runs into a single, combined run and then manually subtract out impacts resulting from quarry emissions at quarry receptors. Post-processing software would have been needed to look at the each emission source's contribution to each receptor on a day-by-day basis. The developed software would have to identify if a receptor was located within the quarry's airspace, and if so, subtract the quarry's contribution leaving only the non-quarry contributions. However, since adding the maximum impacts from each run is a more conservative approach to evaluating NAAQS and PSD increment compliance than a single, combined run, the analysis is acceptable if the sum of the maximums is lower than the applicable NAAQS and PSD increment.

As such, MDEQ disagrees that impacts from quarry emissions within the quarry's airspace should have been included in the modeling analysis

Comment:

MDEQ and the Applicant used inappropriately low background levels for NAAQS modeling.

Response:

As discussed in response to a previous comment, the MDEQ has the authority to use regional monitors, if no other monitors are in the vicinity. 40 CFR part 51, appendix W (Guideline on Air Quality Models) Section 8.2.2(c). The commenters claim the regional monitor data should not be used because the applicant initially proposed to perform its own particulate monitoring.

Prior to receiving the monitoring waiver, the applicant proposed a plan for particulate monitoring in the case the waiver request was denied. Once the waiver was granted, the applicant was not obliged to continue with its proposed monitoring. However, the applicant chose to proceed with its independent monitoring plan for PM10 and PM2.5. The applicant ran a PM10 monitor for six months, submitted the data to the EPA and MDEQ, and did not (contrary to the commenters' suggestion) try to hide incriminating data. The PM10 monitoring program was discontinued for budgetary reasons and because results were not significantly different than the MDEQ monitor chosen for regional background.

The PM2.5 monitor experienced a host of technical difficulties including a lightning strike in early July 2007 which destroyed the monitor after three months of operation. With the reported difficulties, questionable quality data, and short span of data, that data were never submitted to EPA. Since PM2.5 modeling was not required at the time, the applicant chose to discontinue PM2.5 monitoring. With the short time span of monitoring (three months for PM2.5 and six months for PM10), there was not sufficient data to qualify for background use. Additionally, since the PM10 results closely resembled the chosen MDEQ regional monitor,

there was no compelling reason to override the regional monitor as representative. Additional explanation regarding the use of regional monitoring data is provided in response to a previous comment.

Comment:

The modeling inappropriately used annual average emissions to estimate short-term impacts, thus significantly underestimating short-term impacts.

Response:

All short-term modeling from proposed Wolverine sources were based on the worst-case, short-term emissions scenario. For all pollutants which had a short-term threshold, the same short-term emission rate was also used for long-term impacts. Emissions reporting requirements do not include maximum single day emissions or maximum hour emissions. For those offsite sources (i.e. quarry and other non-Wolverine emission sources), the only available data reported to the State are tons per year (tpy) and hours of operation. Offsite short-term emissions are derived by dividing annual emissions by the total annual hours of operation.

Comment:

The modeling is based on inappropriately low lb/hour figure for NOX from the black start generator that does not correspond to the draft permit limits on the black start generator.

Response:

Although the maximum unrestricted hourly NOx emission rate for the black start generator is 86.4 lbs/hour, black start generator emissions are limited by a permit condition that restricts operation of the generator to 500 hours per 12-month rolling time period. The modeled NOx emission rate was "annualized" based on operation of the generator as restricted by the permit. The annualized NOx emission rate was derived per the following: $86.4 \text{ lb/hours} \times 500 \text{ operating hours/year} / 8760 \text{ total hours/year} = 4.9 \text{ lbs/hour}$. The modeling is therefore based on the correct annualized lbs/hour emissions for NOx from the black start generator.

Comment:

The increment analysis must include emissions during startup and shutdown.

Response:

The increment and NAAQS analyses were based on the proposed pound per hour limits in the draft permit, which include emissions during startup and shutdown.

Comment:

The increment analysis omits emissions from haul trucks at receptors on the Carmeuse property.

Response:

New haul truck emissions, resulting from the proposed facility, were included in the increment analysis.

Comment:

The increment analysis omits mobile source combustion emissions from trucks and barges.

Response:

By administrative rule, emissions that come directly from mobile sources such as motor vehicles or vessels, are excluded from the increment analysis. Pursuant to Rule 1811 of the Michigan Air Pollution Control Rules, Wolverine must demonstrate that the allowable emission increases from the proposed facility, in conjunction with all other applicable emission increases or reduction, including "secondary emissions," shall not cause or contribute to an exceedance of the PSD increments. Rule 1801(pp) defines secondary emissions and excludes "any emissions which come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel." Emissions from trucks and barges were correctly excluded from the increment analysis.

Comment:

Combustion emissions from increased truck and barge traffic must be included in the air quality component of the additional impacts analysis.

Response:

Similar to the previous comment, the commenter wishes to expand existing broad regulations to include vehicle combustion emissions. The commenter uses broad definitions contained in State and Federal guidance to suggest that because vehicle combustion emissions are not specifically excluded (other than Michigan Rule 212), inclusion is mandated. As answered in the previous comment, emissions from trucks and barges were correctly excluded from the increment analysis.

Comment:

The Permit is based impermissibly on the illegal and unsupported use of PM10 as a surrogate for PM2.5 in the modeling demonstration.

Response:

Although not required by federal or state law, Wolverine Power Supply Cooperative, Inc. has requested that the MDEQ, rather than use PM10 as a surrogate for PM2.5, include an emission limit in the permit that reflects the best available control technology (BACT) for PM2.5. Wolverine submitted a "top-down" BACT assessment for PM2.5. It also submitted a complete air quality analysis that includes a modeling demonstration showing that emissions from the proposed facility will not exceed the national ambient air quality standards for PM2.5. The air quality analysis further shows that PM2.5 emissions will not exceed final NAAQS thresholds nor the increments for PM2.5 as proposed by EPA.

Comment:

The Applicant did not conduct site-specific preconstruction monitoring for PM2.5.

Response:

As explained in a previous response, the applicant applied for and received a waiver from preconstruction monitoring. EPA regulations, specifically 40 CFR 51, Appendix W, Section 8.2.2(c), states that "If there are no monitors located in the vicinity of the source, a "regional site" may be used to determine background. A "regional site" is one that is located away from

the area of interest but is impacted by similar natural and distant man-made sources.” Representative data are not always determined by which monitor is closest to the subject area. Although not required at the time of the applicant’s waiver request, PM2.5 background data were included in the original supplied data inventory. That data was collected from the Alpena monitor, approximately 45 kilometers southeast of Rogers City. When the applicant provided notice to MDEQ that they intended to go forward and perform PM2.5 modeling, a more detailed review was conducted to determine the most representative PM2.5 data. It was determined that the Alpena data was likely not the most representative regional data because it was over five years old and from a low percentage upwind direction. Although further in distance, approximately 140 kilometers from the proposed facility, the Missaukee County monitor was determined to be more representative of the Rogers City regional background because 1) the data was current; and 2) the monitor was a predominant upwind direction (southwest).

Prior to receiving the waiver, the applicant made plans to monitor for PM10 and PM2.5. Although the granted waiver ultimately negated the necessity for onsite particulate monitoring, the applicant still independently installed PM10 and PM2.5 monitors. As discussed in response to a prior comment, the PM10 monitor ran for six months and the data posted to the EPA network for ambient monitoring data. The PM2.5 monitor experienced a host of technical difficulties and was ultimately destroyed by lightening after three months of monitoring and was not continued.

As stated previously, the commenters seek to invalidate the provisions in 40 CFR Part 51, Appendix W that authorize the use of regional site monitors. The commenters' effort to challenge such nationally applicable regulations must be filed in the U.S. Court of Appeals for the District of Columbia, not in this permit proceeding. The MDEQ does not have the authority to invalidate these provisions.

Comment:

The Applicant’s late-submitted PM2.5 modeling contains numerous omissions and errors that, if corrected, would result in violations of the PM2.5 NAAQS and increments. The Applicant failed to base the background concentrations from preconstruction monitoring data and instead used an inappropriately low background concentration for PM2.5 based on non-representative regional site monitors.

Response:

The Applicant voluntarily performed dispersion modeling for PM2.5. As discussed above, the Applicant used background ambient air quality data from a monitor in Missaukee County because the data are representative of ambient air quality at the proposed facility after taking into account monitor location, quality of the data and currentness of the data. MDEQ has reviewed the dispersion modeling analysis for PM2.5, and it demonstrates that emissions from the proposed facility will not result in an exceedance of the NAAQS for PM2.5. The analysis further shows that PM2.5 emissions will not exceed the increments for PM2.5 as proposed by EPA.

In addition, the Applicant applied for and lawfully received a waiver from site-specific preconstruction monitoring pursuant to 40 CFR 52.21, Appendix W.

Comment:

The Applicant completely omitted secondary emissions.

Response:

EPA currently recommends that only primary PM_{2.5} emissions be included in NSR modeling. This is because of two primary reasons: First, the current near-field models for NSR (i.e. AERMOD) are simple Gaussian dispersion models and cannot do the chemistry required for secondary emissions. The continental and regional models, which include chemistry, are not designed for single source applications. If permitted, these sources will be included in the regional models for regional SIP analyses. Additionally, PM_{2.5} secondary chemistry is complex and can require hours, days, or weeks to form particulates. As such, the reactions occur far outside the near-field grid of the available NSR models.

Comment:

The Applicant used an inappropriate radius of impact.

Response:

The receptor grid for PM_{2.5} is the same as for the PM₁₀ analysis. The applicant performed a "Significant Impact Analysis" for PM₁₀ to determine the maximum distance to a significant impact receptor. As discussed in response to a previous comment, a facility does not cause or contribute to a NAAQS or increment violation where its emissions have an insignificant impact. It is therefore appropriate to exclude receptors outside the distance of the maximum significant impact receptor. Since primary PM_{2.5} is a subset of PM₁₀, the significant impact radius can be no greater than the radius for PM₁₀. Secondary PM_{2.5} emissions are not included in the air quality analysis. The Applicant omitted combined impacts from the Proposed Coal Plant and quarry at receptors on O-N quarry property. The air over secured property is considered "non-ambient" relative to that facility's emissions. The impacts from quarry emissions on receptors within the quarry's secured property were correctly excluded from the modeling analysis.

Comment:

MDEQ's re-analysis also fails to show protection of the NAAQS and increments.

Response:

The commenters accuse MDEQ of "modeling away" a predicted violation of the PM_{2.5} because the agency reviewed the applicant's submitted air quality analysis and revised calculations that overestimated the impacts of emissions. The role of the agency is to determine whether the legal requirements for a proposed facility have been satisfied. In fulfilling that role and reviewing a permit application, the MDEQ may appropriately revise errors in the applicant's analysis.

In the instance of preliminary modeling PM_{2.5} for 24-hour NAAQS compliance (September 30, 2008), the MDEQ modified some of the supplied input parameters to be consistent with previous PM₁₀ modeling and performed further analysis to evaluate the applicant's claim of compliance. The applicant was notified that the agency modified some of the supplied information and was performing additional analysis. MDEQ's additional analysis involved combining the separate runs together, at the maximum impact receptors, to determine if the overall maximum combined impacts achieved NAAQS compliance to the satisfaction of the agency. In the final submitted PM_{2.5} analysis (July 29, 2009), the

applicant provided the rationale for their original emission factors, which was accepted and used by the MDEQ for the final NAAQS and increment results.

The final 24-hour PM_{2.5} NAAQS impact, with 2005-2008 background, was 31.5 ug/m³, less than the threshold of 35 ug/m³. The final 24-hour PM_{2.5} increment impact was 7.8 ug/m³, less than EPA's proposed threshold of 9 ug/m³. Annual impacts for both NAAQS and proposed increment were less than 80% of the thresholds.

Comment:

The NAAQS for PM_{2.5} promulgated by EPA are inadequate to protect public health, and Rule 901 requires comparison of PM_{2.5} modeling impacts to levels that are truly protective.

Response:

EPA set the primary NAAQS for PM_{2.5} to protect the public health, including the health of sensitive populations such as, children, the elderly, and people with asthma. It set the secondary PM_{2.5} NAAQS to protect the public welfare, including crops, trees and buildings. MDEQ promulgated the Part 18 rules of the Air Pollution Control Rules to ensure that new major emitting facilities in areas that have attained the NAAQS do not cause or contribute to a violation of these standards.

Unlike the NAAQS that protect the public health and public welfare generally and take into account emissions from diverse mobile and stationary sources, Rule 901 addresses the impact of emissions from an individual facility. It prohibits a person from emitting an air contaminant that causes injurious effects to human health or safety, animal life, plant life of significant economic value, or property; or which causes unreasonable interference with the comfortable enjoyment of life and property. It does not authorize the establishment of ambient air quality standards to protect the public health at concentrations below the NAAQS set by EPA, nor does it authorize emission limits to achieve any such standards.

E. Maximum Achievable Control Technology (MACT) Review

Comment:

The permit does not contain terms and conditions requiring maximum achievable control technology (MACT) for mercury and other hazardous air pollutants (HAPs).

Response:

A case-by-case MACT analysis was performed for mercury and all other HAPs. The Public Participation Documents for Wolverine Power Supply Cooperative, Inc., Permit Application Number 317-07 contains a "Notice of Maximum Achievable Control Technology (MACT) Approval." The MDEQ performed the case-by-case MACT analysis pursuant to the federal regulations that implement Section 112(g) of the Clean Air Act, 40 CFR §§ 63.40 to 63.44 and 63.50 to 63.56, that are adopted by reference in Rule 336.1299(2)(b) of Michigan's Air Pollution Control Rules.

Comment:

The Draft Permit purports to meet MACT requirements for the Proposed Coal Plant's HAPs, but it does not. The Draft Permit is deficient because the MACT determination fails to

establish an emission limit for each HAP the Proposed Coal Plant would emit, including but not limited to dioxins, radionuclides and cyanide. These HAPs are ignored.

Response:

The permit contains emission limits for each HAP that will be emitted by the emission units at the proposed facility to which the MACT requirements apply: the two CFB boilers and the auxiliary boiler. Dioxins are organic HAPs. Dioxins are included in the VOC emission limit that is a surrogate for organic HAPs. Radionuclides are emitted in the form of particulate and are covered under the PM emission limit as a surrogate. Cyanides are inorganic HAPs along with HCl and HF, and are listed in the Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units, Final Report to Congress.¹³ HCl and HF are the surrogates for acid/inorganic HAPs which includes cyanides.

Comment:

The MACT limit set in the draft permit for mercury does not meet stringent MACT standards. None of the limits are based on proper "MACT floor" analyses, nor did MDEQ undertake any beyond-the-floor investigation, as required. Once the MDEQ revises its MACT determination by performing a complete assessment of the Proposed Coal Plant's likely HAPs and establishing real MACT limits for those HAPs, the MDEQ must then take a new look at the Project's Best Available Control Technology (BACT) limits since the MACT limits for the various surrogates are based on the BACT limits.

Response:

MDEQ disagrees with this comment. As described in the Public Participation Documents for Wolverine Power Supply Cooperative, Inc., Permit Application Number 317-07, the MACT floors were identified and beyond-the-floor investigation was performed for each. The best controlled similar source(s) for all MACT limits was identified after extensive research through all available sources of information (relevant proposed regulations, EPA - TTN RACT/BACT/LAER Clearinghouse (RBLC), permitting activities in other states, literature, etc.) and included surveying emission limits and test results.

Each MACT emission limit was analyzed using the appropriate procedures to meet MACT. The MACT emission limits are not based on a BACT analysis for the limits. In some cases, the MACT limit which is considered a more stringent requirement has lowered BACT limits for those pollutants which are surrogates and PSD/criteria pollutants. This happened with hydrogen fluoride (HF) which is one of the surrogates for acid/inorganic HAPs and volatile organic compounds (VOCs) which is the surrogate for organic HAPs. The original proposed BACT emission limit for HF was 0.0017 lb/MMBtu. The MACT determination resulted in lowering this limit to 0.0003 lb/MMBtu. For VOCs, the original proposed BACT emission limit was 0.0035 lb/MMBtu and the MACT determination resulted in 0.0030 lb/MMBtu.

Comment:

The Draft Permit does not include adequate MACT limits for each and every hazardous air pollutant that will be emitted by the Proposed Coal Plant. The Act requires that emission limits be established for each and every HAP that a facility will emit. The U.S. EPA has identified 67 different HAPs that are emitted by coal-fired power plants. The draft permit fails to do so by omitting entirely several HAPs from the list of relevant HAPs, as well as

¹³ Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, EPA-453/R-98-004a, February 1998, Volume 2, Table A-1.

inappropriately grouping HAPs together and using surrogates in place of limits on the HAPs themselves. The MACT approval, specifically lists the following HAPs scattered throughout the text: mercury; the “acid/inorganic HAPs” HCl and HF; the “metal (particulate) HAPs” antimony, arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium; and unnamed “organic HAPs.” Absent any specific list beyond these HAPs, this list serves as the only guide to the covered HAPs.

EPA’s report to Congress lists numerous additional HAPs that are not included in the WCEV MACT analysis. For example, the analysis makes no mention of dioxins (“priority” HAPs identified by EPA), radionuclides, or cyanide, nor include any discussion of whether and how these pollutants are covered within the HAP categories defined or why such HAPs should be excluded, with appropriate technical support.

Response:

The permit establishes emission limits for each HAP the proposed facility will emit. The PM emission limit is the surrogate for metal HAPs. The VOC emission limit is the surrogate for organic HAPs, and HCl and HF are the surrogates for acid/inorganic HAPs.

The application covers all regulated pollutants that will be emitted by the facility. A complete list is in the Public Participation Documents for Wolverine Power Supply Cooperative, Inc., Permit Application Number 317-07, Appendix 2, Table – Toxic Air Contaminant Impacts – TAC / HAP. Table 1 below identifies the HAPs in three groupings: non-mercury metal (particulate) HAPs, acid/inorganic HAPs, and organic HAPs.

TABLE 1

HAP	HAP Grouping
Mercury	Mercury
Hydrogen chloride Hydrogen fluoride Cyanide	Acid/inorganic HAPs
Antimony Arsenic Beryllium Cadmium Chromium, total Chromium, hexavalent Cobalt Lead Manganese Nickel Phosphorus ¹⁴ Selenium	Non-mercury metal (particulate) HAPs
Acetaldehyde Acetophenone Acrolein Benzene	Organic HAPs

¹⁴ Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, EPA-453/R-98-004a, February 1998, Volume 2, Table A-1.

HAP	HAP Grouping
Benzyl chloride Bromoform Methyl bromide 1,3-Butadiene Carbon disulfide Chlorobenzene Chloroform Cumene 1,4-Dichlorobenzene ¹⁵	
Methylene chloride Dimethyl sulfate 2,4-Dinitrotoluene Ethylbenzene Ethyl chloride Ethylene dibromide 1,2-Dichloroethane Formaldehyde Hexane Isophorone Methyl chloride	Organic HAPs (cont.)
Methyl hydrazine Methyl methacrylate Methyl tert butyl ether Phenol Propionaldehyde Styrene Tetrachloroethylene Toluene Vinyl acetate Xylenes alpha-Chloroacetophenone 2-Methylnaphthalene ³ 5-Methyl chrysene Acenaphthene Acenaphthylene Anthracene Benzo(a)anthracene ³ Benzo(a)pyrene Benzo(b)fluoranthene ³ Benzo(b,j,k)fluoranthene ³ Benzo(g,h,i)perylene Benzo(k)fluoranthene ³ Biphenyl Chrysene ³	

¹⁵ Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, EPA-453/R-98-004a, February 1998, Volume 2, Table A-4.

HAP	HAP Grouping
Dibenzo(a,h)anthracene ³ Fluoranthene Fluorene Indeno(1,2,3-cd)pyrene Naphthalene Phenanthrene Pyrene Total Dioxin/Furan Methyl ethyl ketone (delisted 12-15-05) Methyl chloroform 1,1,2-trichloroethane ³	
Bis(2-ethylhexyl) phthalate Carbon tetrachloride ³ Dibutyl phthalate ³ Hexachlorobenzene ³ Methyl iodine ³ Methyl isobutyl ketone ³ n-nitrosodimethylamine ³ Cresols ³ Perylene ³ Pentachlorophenol ³ Phthalic anhydride ³ Quinoline ³ Trans-1,3-dichloropropene ³ Trichloroethylene ³	Organic HAPs (cont.)
Vinylidene chloride ³ 1-methylnaphthalene ³ 2-chloronaphthalene ³	

Dioxins are organic HAPs. Radionuclides are covered under the surrogate PM emission limit. Cyanides and its chemical forms are inorganic, and are covered under the HCl and HF surrogacy for acid/inorganic HAPs. All HAP emissions that the boilers are expected to emit are appropriately covered in the permit application and limited in the draft permit.

Comment:

The MACT analysis is based on inappropriate grouping of HAPs and the use of inappropriate surrogates for each group. The Draft Permit only contains direct MACT limits for mercury, hydrogen chloride, and hydrogen fluoride. In addition, the MDEQ treated groups of HAPs together and set limits on surrogate pollutants as MACT for each group. In sum, MDEQ considers and purportedly includes limits on four categories of HAPs: mercury, metallic HAPs, organic HAPs, and inorganic HAPs. This approach both fails to set limits for all HAPs and unjustifiably uses surrogates for others.

Response:

Links and relationships were established between each surrogate and its respective group of HAPs. As discussed in more detail below, each of the surrogate emission limits satisfy the legal standard for using a surrogate pollutant for a group of HAPs: (1) the HAPs are invariably present in the surrogate pollutant; (2) the control technology for the surrogate

pollutant indiscriminately captures the HAPs along with the surrogate pollutant; and (3) the control for the surrogate pollutant is the only means by which facilities achieve reductions in emissions of the HAPs. *NDRC v EPA*, 353 F3d 976, 984 (DC Cir 2004); *National Lime Ass'n v EPA*, 233 F3d 625, 639 (DC Cir 2000).

As also discussed below, the surrogate emission limits satisfy the MACT requirements because they are not less stringent than the emission control achieved in practice by the best controlled similar source and they reflect the maximum degree of reduction in emissions that the MDEQ, taking into consideration the cost of achieving such emission reductions and any non-air quality health and environmental impacts and energy requirements, has determined is achievable by the proposed facility.

Comment:

An emission limit for filterable particulate matter is not a proper surrogate for non-mercury metallic HAPs because it does not satisfy the legal standard for using a surrogate pollutant for a group of HAPs. First, HAP metals are not invariably present in particulate matter at the inlet to the fabric filter because some HAP metals (such as arsenic and selenium) are present as gases at that location. Second, particulate controls for coal plants do not indiscriminately capture HAP metals because they do not capture HAP metals at the same rate as other particulates and, instead, favor larger, non-metallic HAP-laden particles. Fabric filters allow most of the metallic HAPs (which exist primarily in smaller particles) to escape. Third, facilities achieve reductions in HAP metal emissions by means other than PM control such as switching fuels. In addition, switching fuels would decrease HAP metal emissions without a corresponding reduction in PM emissions.

Response:

The use of PM as a surrogate for non-mercury metal (particulate) HAPs is reasonable based on the criteria established by the U.S. Court of Appeals for the D.C. Circuit: (1) non-mercury metal HAPs are invariably present in PM; (2) PM control technology indiscriminately captures non-mercury metal HAPs along with other particulates; and (3) PM control is the only means by which facilities achieve reductions in non-mercury metal HAP emissions. *National Lime*, 233 F3d at 639; *Sierra Club*, 353 F3d at 984.

First, PM generated by coal-fired combustion units invariably contains metal HAPs. Bituminous and subbituminous coals can contain antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.¹⁶ These metal HAPs are released when coal is combusted. In elemental form, most of these metal HAPs have boiling points greater than 1,000°F. The exceptions are lead with a boiling point of approximately 620°F and selenium with a boiling point of approximately 420°F.¹⁷ The exhaust gas temperatures in the fabric filter will be approximately 200°F. At these temperatures, metal HAPs will be solid and in a particulate form that can be removed from the exhaust gases prior to discharge out of the stack. Research on bituminous and subbituminous coals has shown that trace metallic element concentrations in the fly ash fraction exist in both PM <2.5 µm and PM >2.5 µm. Measurements of PM from fabric filters indicate collection efficiencies of greater than 99% for particulates with diameters of 0.02 to 10 µm. For the bituminous and

¹⁶ Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating units – Final Report to Congress, EPA-453/R-98-004a, February 1998, Volume 2, Table A-1.

¹⁷ CRC Handbook of Chemistry and Physics, 53rd Edition, 1972-1973.

subbituminous coals analyzed, 4 to 7% of the particulate matter from fabric filters was <2.5 µm while the remainder was >2.5 µm.¹⁸

Second, the PM control required by the proposed permit (a fabric filter) indiscriminately captures non-mercury metal HAPs along with other particulates, regardless of whether the fabric filter does not capture PM and some non-mercury metal HAPs at the same rate. When the fabric filter removes PM, non-mercury metal and particulate HAPs are also removed.

Third, the commenter does not identify any similar sources that, by switching fuels, achieve reductions in non-mercury metal HAPs emissions without a corresponding reduction in PM emissions. Similarly, the MDEQ has not identified any such sources. PM is the only means by which similar sources achieve reductions in the emission of non-mercury metal HAPs, regardless of the potential variability of non-mercury metal HAPs in different fuels. The criteria for the reasonable use of PM as a surrogate for non-mercury metal HAPs is satisfied.

U.S. EPA has used filterable PM as a surrogate for non-mercury metal HAPs from various source categories, including glass manufacturing facilities, chemical manufacturing areas, and mineral wool production facilities. 72 Fed Reg 73,180 (Dec. 26, 2007); 72 Fed Reg 38,884 (July 16, 2007); 64 Fed Reg 29,491 (June 1, 1999).¹⁹ Other states have used filterable PM as a surrogate for HAP metal emissions in their case-by-case MACT determinations.²⁰

Comment:

MDEQ's proposal to group together all organic HAPs from the Proposed Coal Plant and use VOCs as a surrogate is unsupported and VOC is not a proper surrogate for the organic HAPs group. There is no explanation of whether or how the "organic HAPs" grouping is appropriate. In fact, the behavior of the various organic HAP compounds are dissimilar in terms of, for example, how some are formed and their fate after leaving the boiler. There are also different classes of organic HAPs (volatile, semi-volatile, and particulate compounds) that behave differently during combustion. In addition, VOC control does not indiscriminately capture organic HAPs, and facilities achieve reductions in organic HAP emissions by means other than VOC control. VOC cannot be a surrogate for HAPs.

Response:

VOCs are an appropriate surrogate for organic HAPs based on the three-part legal standard for surrogates. First, all organic HAPs from the proposed facility are invariably present as VOCs. As explained in the Public Participation Documents, organic HAPs are a subset of VOCs and are produced during the combustion of coal. Second, organic HAPs and VOCs are produced as a result of incomplete combustion. Good combustion practices that promote complete combustion of coal in the boiler is an effective pollution control measure

¹⁸ Comparison of Particle Size Distributions and Elemental Partitioning from the Combustion of Pulverized Coal and Residual Fuel Oil, Journal of the Air & Waste Management Association, Volume 50, August 2000, pp. 1532 – 1544.

¹⁹ EPA also used filterable PM as a surrogate for HAP metals in its MACT standard for Industrial/Commercial/Institutional Boilers and Process Heaters. 69 Fed Reg 59,218 (Sept. 13, 2004). Although the standard was vacated by U.S. Court of Appeals for the D.C. Circuit, the court's ruling was not based on the use of filterable PM as a surrogate. 489 F3d 1250 (DC Cir 2007).

²⁰ See e.g., Georgia Dept. of Nat. Res., Environmental Protection Division, Notice of MACT Approval for Longleaf Energy Associates, LLC (June 2009); South Carolina Dept. of Health and Env. Control, Bureau of Air Quality, Final Determination and Final Notice of MACT Approval for Santee Cooper Pee Dee Generating Station (Dec 16, 2008).

for VOCs and indiscriminately captures both VOCs and organic HAPs. Third, similar sources do not use means other than good combustion practices to control organic HAPs.

Comment:

There are pollution-control methods that would reduce the Proposed Coal Plant's organic HAP emissions without producing a corresponding reduction in the plant's VOC or CO emissions. Combustion optimization will increase some organic HAPs, reduce some organic HAPs, and have no effect on other organic HAPs. Other VOC controls, such as substituting alternative fuels (natural gas, or distillate oil) would reduce organic HAPs at a far higher rate than they would reduce carbon monoxide.

Response:

The MDEQ has not identified any similar facilities that employ such other means and the commenter has not identified any such facilities. Other similar facilities use good combustion practices to reduce organic HAP emission regardless of the type of fuel combusted.

Comment:

The Draft Permit proposes to require as a surrogate a VOC limit that is subject to only periodic (annual) stack testing. Such stack testing is further evidence that VOC is an improper surrogate because, measured occasionally, VOC emissions lack the necessary indiscriminating correlation with organic HAP emissions. Organic HAPs that are caused by incomplete combustion can be produced in large quantities during short "hot spot," incomplete-combustion events, such as burner malfunction, startups and shutdowns. Infrequent stack testing likely occurs outside of these periods and fails to capture the organic HAP emissions during these "hot spot" events. The periodic testing further demonstrates that VOCs are not an appropriate surrogate for organic HAP emissions.

Response:

Periodic stack testing of VOC emissions is only one permit requirement to ensure good combustion practices. CO is formed as a result of incomplete combustion of a hydrocarbon fuel. The permit requires that Wolverine demonstrate good combustion control by continuous monitoring of CO emissions. Continuous monitoring of CO emissions is used to, among other things, reduce the air to fuel ratio to ensure the maximum combustion of fuel, which in turn ensures minimum VOC emissions, including organic HAPs. In addition, continuous monitoring of CO assures minimization of organic HAP emissions at all times.

Comment:

VOC cannot be used as a surrogate for organic HAPs because the MDEQ has not shown that more specific, tailored limits for organic HAPs are not feasible. The applicant should be required to set limits upfront on individual HAPs and organic HAP subgroups and conduct post-construction testing (particularly for cyanide and dioxins) and revise limits as appropriate.

Response:

The feasibility of limits tailored to organic HAPs is not the legal standard for determining whether it is reasonable to use a surrogate emission limit for a group of HAPs. As discussed previously, the U.S. Court of Appeals for the D.C. Circuit has established a three-part legal

standard for using surrogates. The MDEQ has satisfied that standard in using VOCs as a surrogate for organic HAPs.

The VOC emission limit is the surrogate limit for organic HAPs. Post-construction testing is required to demonstrate compliance with that limit. Given the lack of individual limits for each organic HAP, stack testing for individual organic HAPs is not required. The individual HAPs that will be emitted from the proposed facility and that are included in the organic HAPs group are listed in Table 1.

Comment:

Any surrogate MACT limit for VOC must be based on a short-term average, on the order of one hour. Compliance with periodic stack tests of VOC, as is currently required by the permit, will not protect against very high organic HAP emissions that can occur over short periods.

Response:

The averaging time is defined by the test protocol as required by Rule 1003(5) of Michigan's Air Pollution Control Rules. That rule states: "Minimum sample time shall be 60 minutes, which may be continuous or a combination of shorter sampling periods for sources that operate in a cyclic manner." Compliance with the VOC emission limit will therefore be based on a short-term average. As for "very high organic HAP emissions that can occur over short periods," spikes in organic HAP emissions will be minimized because good combustion will be monitored continuously through CO emissions.

Comment:

For acid/inorganic HAPs and HCl/HF as surrogates, MDEQ must confirm whether cyanides are considered as part of the inorganic HAPs group or some other group/surrogate. If cyanides are not considered as part of any of the groups, MDEQ must address this omission before issuing a revised permit.

Response:

Cyanides are considered inorganic compounds. The surrogates for cyanides are HCl and HF. Cyanides will be controlled using the same reduction techniques used for HCl and HF, and reduction in HCl and HF emissions will be indicative of reductions in cyanides.

Comment:

MDEQ failed to properly assess the MACT floor for each HAP. The permit limits do not constitute MACT, as they are not based on the emissions achieved in practice by the best controlled similar source. Neither Wolverine nor the MDEQ has correctly identified the "best controlled similar source" for each of the HAPs emitted by the WCEV. MDEQ inappropriately narrowed the universe of "similar source," resulting in MACT limits impermissibly based on the Applicant's preferred configurations and control strategy for meeting BACT requirements.

Response:

"Similar source" is defined in both the federal regulations and Michigan's Air Pollution Control Rules as "A stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the

source could be controlled using the same control technology." 40 CFR 63.41; 2008 AACS, Rule 299(2)(b).

The MDEQ identified the best controlled similar source for all MACT limits after extensive research. The MDEQ's review included a thorough search of emission limits and test results, EPA's TTN RACT/BACT/LAER Clearinghouse (RBLC), proposed regulations, and literature. Information from over 70 power plants, including PC boilers and CFB boilers, was surveyed in the MACT determination. As discussed below, the MDEQ correctly established MACT limits for the HAPs to be emitted from the proposed facility.

Comment:

The MDEQ does not "make a reasonable estimate of the performance" of the best-controlled unit in the appropriate category, but references only a select few other power plants for all of the HAPs in question. While several plants are addressed for mercury alone, the only comparison for all the other HAPs (albeit with regard to inappropriate surrogates) appears to have been the JEA Northside plant in Florida. This limited citation and failure to compare sources in the determination itself is insufficient to set MACT. In other words, the agency started with the applicant's proposed boiler and the fuel selected by the applicant for the mercury MACT analysis (notably only one of the many fuels the boiler will be capable of burning) and eliminated any sources that did not fit that exact configuration. This narrowing is arbitrary and capricious.

Response:

Information from over 70 power plants was surveyed for best controlled similar sources and used in the MACT determination. Four sources were highlighted as best for a number of different HAPs. A large source pool of information was developed to compare sources for the MACT determination that was sufficient.

PC boilers burning bituminous and subbituminous coal, and petroleum coke (not an "exact configuration") were not omitted or eliminated from the MACT determination. For the mercury emission limit and other MACT limits, all possible fuel combinations had to be evaluated and the emission limit assessed for continuous compliance under all operating scenarios. This is not a "narrowing" that "is arbitrary and capricious," but a broad analysis to derive an emission limit.

Comment:

The MACT limit may not be based on the worst case fuel for each HAP or group of HAPs. MACT requires a limit reflecting the maximum degree of reduction in emissions, where "process changes" and "substitution of materials" must be considered as control options. Using a different fuel qualifies as a process change and/or substitution of materials. Where, as here, a source is entirely capable of burning a range of fuels, it is wholly inappropriate to base MACT on the worst possible fuel for each HAP or group of HAPs.

Response:

The CFB boilers are designed and capable of burning a range of different fuels. The type and amount of fuel combusted in the CFB boilers is closely tied to availability (e.g., transportation, cost, growing seasons, etc.). In addition, the permitted operation of the units is for a blend or variety of fuels to be fired at any given time. The MACT determination was

based on the maximum achievable control for the types of fuels proposed to be combusted while maintaining fuel flexibility as a practical consideration.

Comment:

It is appropriate to set separate MACT limits for each fuel – i.e., PRB coal, Illinois bituminous coal, pet coke, and biomass.

Response:

Setting separate limits was evaluated and deemed impractical for CFB boilers designed for fuel flexibility. Also, setting a limit specific to each fuel type may not result in additional reductions in HAPs because the type of fuel that will be combusted in the boiler will be determined based on availability.

Comment:

MDEQ also improperly selected purportedly appropriate control technologies based on the Applicant's proposal, and calculated emissions limits based on the expected performance of these technologies. While control methods and technologies are part of the MACT analysis, the MACT floor is not set by reference to particular technologies. The MDEQ must base its limits on the actual emissions of the best controlled existing source.

Response:

The MDEQ based its MACT floor determinations on the actual emissions (i.e., data from test results) for each best controlled similar source. In addition, the MACT emission limits need to account for variability in fuels and corresponding performance in the pollution controls to assure the emission limit represented by the best controlled similar source can be achieved consistently. To ensure the MACT emission limits are based on realistic operation rather than solely on test results from stack tests performed under optimum conditions, the MDEQ used safety factors in calculating the limits. The safety factors take into account the fuel characteristics and variability in the anticipated performance of the pollution controls for mercury and the HAP surrogates. Also, if test data does not fully represent the source or is very scarce, safety factors are adjusted to account for the quality and quantity of data used to establish the MACT emission limit. Safety factors are calculated based on the statistical variability of the data available.

Comment:

The MDEQ's proposed MACT limit for non-mercury metallic HAP is a filterable PM10 emission limit of 0.010 lb/MMBtu, based on an unspecified averaging time to be determined later in a test protocol. Even if all of the other portions of the analysis were acceptable, the lack of averaging time renders this MACT determination deficient.

Response:

The averaging time is defined by the test protocol as required by R 336.2003. Specifically, "Minimum sample time shall be 60 minutes, which may be continuous or a combination of shorter sampling periods for sources that operate in a cyclic manner." This meets the requirements of the NSR Manual for a "reasonable averaging time in order to be enforceable."

Comment:

The proposed limit of 0.010 lb/MMBtu is greater than the MACT floor. A stack test at Santee Cooper's Cross Unit 3 showed filterable PM10 emissions of 0.0099 lb/MMBtu in January 2008. As the PPD notes, even the *highest* PM emission level from JEA Northside, Unit 1 while burning 75% petroleum coke and 25% coal (a blend very close to that identified by Wolverine as its "design fuel"), 0.0091 lb/MMBtu, is below the proposed MACT limit for Wolverine. The PM10 MACT floor should be no greater than 0.006 lb/MMBtu, based on a 3-hour average, or roughly 40% lower than the limit proposed by the MDEQ as MACT.

Response:

The proposed limit and the test results of 0.0099 lb/MMBtu and 0.0091 lb/MMBtu are within the range of the test method accuracy and are basically similar numbers. The emission limit is stringent but not so stringent that it can not be achieved continuously. This was determined based on the fact that JEA Northside for example has emission tests demonstrating lower particulate emission rates under a variety of operating conditions as evidence that the emission limit can be achieved on a continuous basis. The commenter's proposed limit of 0.006 lb/MMBtu does not contain an acceptable factor of safety that would assure continuous compliance.

Comment:

The lowest BACT limits for CO of 0.15 lb/MMBtu (based on a 30-day average) and a VOC limit of 0.003 (based on an unspecified test protocol) are inappropriate for MACT.

Response:

CO is not proposed as a surrogate for organic HAPs, therefore the CO emission limit was not part of the MACT determination. The VOC limit is the surrogate for organic HAPs, and the test protocol will be specified and approved because the draft permit requires submission of an approvable test plan before compliance testing.

The proposed VOC limit of 0.003 lb/MMBtu could have been explained better. VOC emissions from combustion sources are related to the organic content of the fuels combusted and good combustion practices. VOC emissions are uncontrolled and can fluctuate widely, therefore making it difficult to assess an emission limit. Typically, the organic content of subbituminous coal is higher than bituminous coal, and petroleum coke has a lower organic content than coal. The highest organic content fuel that Wolverine is proposing to combust is the biomass. Data is limited for VOC emissions from all of the fuels that Wolverine is proposing to combust. Decisions on the VOC emission limit for Wolverine were mainly based on the performance of JEA Northside which combusts bituminous coal and petroleum coke, two of the lower organic content fuels. The two CFB boilers at JEA Northside had measured VOC emissions of approximately 0.0014 lb/MMBtu when combusting a blend of 90% petroleum coke/10 % coal. This emission rate was higher than the VOC emission rate of 0.00025 lb/MMBtu measured when combusting a blend of 70% petroleum coke/30 % coal. The blend of 70% petroleum coke/30 % coal should contain a higher organic content, and in theory result in higher VOC emissions. In contrast, when combusting 100% coal, unit #1 had VOC emissions of 0.0023 lb/MMBtu measured at 104% of allowed process rate and unit #2 had VOC emissions of 0.000016 lb/MMBtu measured at 92% of allowed process rate. Since VOC emissions were unpredictable and based on lower organic content fuels, a conservative 0.003 lb/MMBtu was assessed for the VOC emission limit which represents a 30% factor of safety over JEA Northside's highest VOC test while combusting coal.

Comment:

The MDEQ has proposed an HCl limit of 0.0011 lb/MMBtu, with an unspecified averaging time. The lack of an averaging time makes this a deficient and unenforceable permit limit. Also, for the purpose of setting the HCl limit, Illinois bituminous coals was considered to be the appropriate fuel, despite the fact that it is intended to be a secondary fuel used when pet coke and PRB are limited due to market conditions. This was done simply to obtain the highest limit possible, as Illinois bituminous coal contains the highest chlorine content of the considered fuels. The fuel on which the limit is based thus has little relationship to how the Proposed Coal Plant will actually operate, making the limit a sham.

Response:

The averaging time is defined by the test protocol as required by R 336.2003. Specifically, "Minimum sample time shall be 60 minutes, which may be continuous or a combination of shorter sampling periods for sources that operate in a cyclic manner." The limit is sufficient and enforceable. The limit of 0.0011 lb/MMBtu encompasses the fact that CFB boilers are designed and capable of burning a range of different fuels. The type and amount of fuel proposed to be combusted in the CFB boilers are closely tied to availability (e.g., transportation, cost, growing seasons, etc.) In addition, the intended operation of the units is for a blend of fuels to be fired at any given time. The MACT determination was based on the maximum achievable control for the types of fuels proposed to be combusted while maintaining fuel flexibility as a practical consideration not "simply to obtain the highest limit possible."

Comment:

The HCl and HF limits appear to be based on specific controls with no proof as to the basis for the 95% control claim. No design details for the controls are provided that would support such a removal efficiency. While such efficiencies are possible, the relevant design parameters should be specified.

Response:

The 95% is based on the best conceptual design for the specific control strategy that is required via permit condition. The engineering design and design-to-build drawings have not been completed for the source so specific design details are not available.

Comment:

The MACT floor should be the lowest limit that is achievable regardless of fuel, as fuel selection is one of the controls for HAPs ("process changes," "design," and "substitution of materials" are pollution-reduction methods that must be assessed as part of a MACT determination). Other states have performed MACT analyses for similar sources and concluded that MACT is much lower than inferred here for the Proposed Coal Plant. Kentucky established a MACT limit for hydrogen chloride of 0.000825 lb/MMBtu in October 2002 for a bituminous coal fired pulverized coal fired boiler.

Response:

Determination of the MACT floor has to take into account fuel. For example, acid gas emissions from the combustion of natural gas are different from acid gas emissions due to coal combustion. What is being combusted is very important in a MACT determination for a

combustion source. The statement that “the MACT floor should be the lowest limit that is achievable regardless of fuel” is incorrect and would lead to an unenforceable limit.

Thoroughbred Generating Station, in Kentucky, will have a wet FGD and wet ESP, and is not strictly speaking a similar source. Since these units are not operating, the HCl emission limit of 0.000825 lb/MMBtu has not been achieved in practice.

Comment:

Stack testing indicates that similar sources routinely achieve lower hydrogen chloride emissions. The Gilbert Unit 3 circulating fluidized bed boiler achieved a hydrogen chloride emission level of less than 0.000056 lb/MMBtu while burning bituminous coal. The U.S. Department of Energy measured hydrogen chloride emissions from 16 different coal burning boilers, including with and without various control options, such as reburn, low NO_x burners and selective noncatalytic reduction. This study demonstrated that several of the facilities emitted lesser amounts of hydrogen chloride than proposed here, over a decade later, as MACT. These include Springerville (less than 0.000176 lb/MMBtu), Yates (0.000742 lb/MMBtu), Bailly (0.00102 lb/MMBtu), Burger using SNCR (0.00077 lb/MMBtu), Arapahoe uncontrolled (0.000630 lb/MMBtu), Arapahoe using SNCR (0.000720 lb/MMBtu), and Shawnee using lime injection with fabric filters (less than 0.000073 lb/MMBtu).

Response:

Testing results for HCl emissions from sources that could be identified as similar to Wolverine’s CFB boilers are limited. And, stack test results represent limited data and may not demonstrate the variability of chlorine in coal and the variability of operating conditions.

The testing information listed by the commenter does not establish that these are similar sources or that the HCl emissions are consistently achieved in practice. Gilbert, Unit 3 combusts a run-of-mine eastern bituminous which is not similar to any fuel Wolverine is proposing to combust. Gilbert is not a similar source based on fuel.

Stack testing is a measure of performance, but the MACT emission limit should not be set at the lowest single test result ever achieved by a best controlled similar source, and when working with small sets of source test data to assess an emission limit, an appropriate safety factor needs to be assessed.

Based on available information, it appears that the MACT emission limit for HCl for Wolverine’s two proposed CFB boilers is appropriate without being too overly conservative.

Comment:

The MDEQ has proposed an HF limit of 0.0003 lb/MMBtu, with an unspecified averaging time. The lack of an averaging time makes this a deficient and unenforceable permit limit. As with HCl, Illinois bituminous coals was considered to be the appropriate fuel. Again as with HCl, this selection was made simply to obtain the highest limit possible and has little direct relationship to how the Proposed Coal Plant will actually operate.

Response:

The averaging time is defined by the test protocol as required by R 336.2003. Specifically, “Minimum sample time shall be 60 minutes, which may be continuous or a combination of shorter sampling periods for sources that operate in a cyclic manner.” The limit is sufficient

and enforceable. The HF limit encompasses the fact that CFB boilers are designed and capable of burning a range of different fuels. The type and amount of fuel proposed to be combusted in the CFB boilers are closely tied to availability (e.g., transportation, cost, growing seasons, etc.) In addition, the intended operation of the units is for a blend of fuels to be fired at any given time. The MACT determination was based on the maximum achievable control for the types of fuels proposed to be combusted while maintaining fuel flexibility as a practical consideration not "simply to obtain the highest limit possible."

Comment:

The MACT floor should be the lowest limit that is achievable regardless of fuel, as fuel selection is one of the controls for HAPs. Other states have performed MACT analyses for similar sources and concluded that MACT for HF is much lower than Wolverine's HF limit. West Virginia issued a permit for the Longview facility, two CFB boilers that will burn bituminous coal, with a hydrogen fluoride limit of 0.00001 lb/MMBtu.

Response:

Determination of the MACT floor has to take into account fuel. For example, acid gas emissions from the combustion of natural gas are totally different from acid gas emissions due to coal combustion. What is being combusted is very important in a MACT determination for a combustion source.

Also, Longview is a proposed pulverized coal-fired boiler not two CFB boilers. The plant has not been built, and therefore the HF emission limit has not been demonstrated as achieved in practice nor is the source considered similar to Wolverine's proposed CFB boilers.

Comment:

Stack testing indicates that similar sources routinely achieve lower hydrogen fluoride emissions. The Gilbert Unit 3 circulating fluidized bed boiler achieved a hydrogen fluoride emission level of less than 0.000056 lb/MMBtu while burning bituminous coal. The JEA Northside circulating fluidized bed boilers tested at less than 0.0000309 lb/MMBtu while burning 100% Pittsburgh 8 coal; at 0.0000169 lb/MMBtu while burning a 50:50 blend of coke and Pittsburgh 8 coal; at 0.00004582 lb/MMBtu while burning 100% Illinois 6 coal; and at less than 0.0000053 lb/MMBtu while burning a blend of 80% coke and 20% Pittsburgh 8 coal.

Further, the U.S. Department of Energy measured hydrogen fluoride emissions from 16 different coal burning boilers, including with and without various control options, such as gas reburn, low NOX burners and selective noncatalytic reduction. This study demonstrated that several of the facilities emitted lesser amounts of hydrogen fluoride than proposed here, over a decade later, as MACT. These include Springerville (<0.000092 lb/MMBtu), Yates (0.000122 lb/MMBtu), Nelson Dewey (0.000067 lb/MMBtu), Burger using SNCR (0.000039 lb/MMBtu), and Shawnee using lime injection with fabric filters (<0.000023 lb/MMBtu).

Response:

The testing information from the U.S. Department of Energy listed by the commenter does not establish that these are similar sources or that the HF emissions are consistently achieved in practice. Gilbert, Unit 3 combusts a run-of-mine eastern bituminous which is not similar to any fuel Wolverine is proposing to combust. Gilbert is not a similar source based on fuel.

Stack testing is a measure of performance, but the MACT emission limit should not be set at the lowest single test result ever achieved by a best controlled similar source, and when working with small sets of source test data to assess an emission limit, an appropriate safety factor needs to be assessed.

As for the proposed HF emission limit, the stack testing results from JEA Northside were revisited. Again, emission limits should not be set at the lowest single stack testing result ever achieved, and JEA Northside has had higher emissions of HF. Unit #2 had HF emissions measured at 0.261 lb/hr (equivalent to 0.00010 lb/MMBtu) while combusting 100% petroleum coke, and while combusting 100% coal, HF emissions were measured at 0.290 lb/hr (equivalent to 0.00011 lb/MMBtu). It is appropriate to lower the proposed HF emission limit for Wolverine's CFB boilers to 0.00014 lb/MMBtu which provides a 30% factor of safety.

Comment:

The MDEQ established the MACT limit for mercury as 0.0077 lb/GW-hr on an annual average basis, using the mercury content of PRB coal. This limit is equivalent to 0.882 lb/TBtu, in terms of heat input.

The one glaring flaw in the calculated limit relates to the use of PRB coal as the basis. The WCEV is expected to use as its fuel up to 70% pet coke, a fuel with very low mercury content. WCEV has every incentive to use as much pet coke as allowed under the permit given the far lower cost of pet coke as compared to other fuels. However, the mercury limit assumes that, on an annual basis, PRB coal will be used at all times. It is clear that the mercury limit is significantly over-estimated. As discussed earlier, without conceding that the MACT limit must be set on the cleanest fuel for mercury, separate mercury limits at least should be developed for each proposed fuel. The annual average mercury limit should then reflect the actual proportion of fuels used and their respective limits.

Response:

As stated earlier, CFB boilers are designed and capable of burning a range of different fuels. The type and amount of fuel proposed to be combusted in the CFB boilers are closely tied to availability (e.g., transportation, cost, growing seasons, etc.) In addition, the intended operation of the units is for a blend of fuels to be fired at any given time. The MACT determination was based on the maximum achievable control for the types of fuels proposed to be combusted while maintaining fuel flexibility as a practical consideration. There is no "glaring flaw" in the use of PRB coal as the basis of the mercury emission limit. Mercury emissions from the combustion of PRB coal are expected to be the hardest to capture and control, and are dependent on the effectiveness of the sorbent injection system. Wolverine's CFB boilers were evaluated to combust up to 100% PRB/subbituminous coal. Setting separate limits was evaluated and deemed impractical for CFB boilers designed for fuel flexibility. Also, setting a limit specific to each fuel type may not result in additional reductions in HAPs because the type of fuel that will be combusted in the boilers will be determined based on availability.

Comment:

If a more thorough analysis had been conducted by the MDEQ, it would have discovered that the best controlled similar source to the Proposed Coal Plant is the Reliant Energy Seward unit, a CFB boiler whose mercury emissions have been tested at 0.03 lb/TBtu. At this rate,

each of the proposed coal plant units would have a mercury emission rate of approximately 0.8 lb/year, instead of the proposed 23.4 lb/yr, a limit that is approximately 29 times greater. In addition, several permits have been issued with lower mercury MACT limits. Utah issued a permit in October 2004 to Intermountain Power Generating Station for Unit 3. This 950-MW pulverized coal-fired boiler will burn subbituminous/bituminous coal. The Intermountain permit contains a mercury MACT limit of 0.006 lb/GW-hr. This is 22% lower than the limit proposed by MDEQ. Virginia issued a permit in June 2008 to Virginia Electric and Power Company for two CFB boilers (Dominion Wise County) with a combined output of 668 MW. These boilers would burn coal and waste coal. The permit contains a mercury MACT limit of 0.000088 lb/GW-hr (0.09 lb/TBtu), or several degrees of magnitude lower than the proposed MACT limit here.

Response:

Seward combusts a waste bituminous coal that Wolverine is not proposing to combust. Therefore, the Reliant Energy Seward unit is not a similar source. The mercury permit limits for Virginia Electric and Power Company, Dominion were based in part on Seward because the Virginia units will be combusting a bituminous coal refuse (gob) and was considered similar to Seward by the permitting agency.

Intermountain Power, Unit 3 is not operating. The mercury emission limits for Intermountain Power (converted to GW) are 0.006 lb/GW-hr per 12-month rolling average for bituminous coal and 0.020 lb/GW-hr per 12-month rolling average for subbituminous coal. The emission limit for subbituminous coal is higher than the emission limit assessed for Wolverine's CFB boilers.

Comment:

Having failed to properly identify the MACT floors, the MDEQ analysis also omits proper beyond-the-floor MACT analyses, as well as the information that would be used in its preparation. This total omission of a required component of the MACT analysis, see 40 C.F.R. § 63.43(d)(2), itself is grounds for invalidating the MACT limits.

Response:

The MDEQ disagrees with this comment. Emission controls and limits beyond what is achieved in practice by the best controlled similar source were reviewed for HAPs. For example, oxidation catalyst control technology (as well as EMx-SCONOX) for organic HAPs, wet ESP for acid gases and metal HAPs, and demonstration technologies such as electro-catalytic oxidation (ECO™) for mercury were reviewed and found to be either not cost effective, technically feasible, demonstrated in practice, and/or available for application to a utility-size CFB boiler.

The beyond-the-floor analysis is not complex for this project. The CFB boilers have the best control to meet the MACT floor. There are not any control options that the MDEQ is aware of that are cost effective, technically feasible, demonstrated in practice and/or available for application on a utility-size boiler to set a MACT emission limit based on a beyond-the-floor control technology.

Comment:

The beyond-the-floor analysis for mercury is lacking. Although brominated activated carbon injection is proposed, no details on this control are provided. At a minimum, the following information must be supplied to support a beyond-the-floor MACT analysis:

- design basis mercury content of each fuel that is proposed;
- uncontrolled mercury emission rate;
- design basis of the activated carbon system, including control efficiency and basis of the carbon injection rate used in the cost analysis;

Without this information, it is unclear if the proposed 93% reduction rate is MACT. In our opinion, 99% mercury control has been achieved and is achievable for the subject units using brominated activated carbon, the ReACT technology, or other technologies that are currently available.

Response:

The design basis for the mercury content of the fuels is 12.6 lb Hg/TBtu. The uncontrolled mercury emission rate for each CFB boiler is 0.038 lbs/hr. The design basis for the sorbent injection system is 93% control and the sorbent injection rate will be dependent on the mercury loading into the system which can be variable. As for 99% mercury control, whether that can be achieved on a continuous basis under all operating conditions is the question. Brominated activated carbon is a mature technology that is commercially available. The same cannot be said for the ReACT technology nor any other technology for mercury control, since they are still in the development stages.

Comment:

The alleged MACT limits are not enforceable. Setting aside the improper use of surrogates, the surrogate limits themselves fail in numerous ways to meet enforceability requirements, as discussed elsewhere in these comments. Limits that are not enforceable are not MACT.

Response:

The permit contains emission limits for HAPs, and testing, monitoring, and record keeping requirements to demonstrate compliance with the emission limits. This makes the MACT limits enforceable.

Comment:

The mercury controls proposed by the MDEQ do not meet the requirements of the Clean Air Act because MDEQ did not do a sufficient MACT analysis, and arbitrarily and without reason rejected lower mercury limits that other plants are proposing to meet.

Response:

The MDEQ disagrees. Operational Memorandum No. 15, "Procedure for Processing Permit Applications Subject to Federal Clean Air Act Section 112(g)" establishes guidelines for processing a permit application for a case-by-case MACT determination. The process of determining what is maximum achievable control technology for a source is called a case-by-case MACT determination, and the implementation regulations are adopted by reference in Rule 336.1299(2)(b).

Comment:

Since your previous permitting action on the proposed Wolverine facility, please be aware that the EPA recently proposed the National Emissions Standards for Hazardous Air Pollutants from Coal-and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel Fired Electric Utility, Industrial-Commercial Institutional, and Small Industrial-Commercial-Institutional Steam Generating (see 76 FR 24976; May 3, 2011). Please ensure that any applicable requirements are reflected in a permit.

Response:

The rule has only been proposed and is not final yet. MDEQ does not put proposed rule requirements in PTI's because the rule may change and then the permit would need to be modified. Also, as stated above, MDEQ properly applied a case-by-case MACT determination.

F. Best Available Control Technology (BACT) Review

1. Integrated Gasification Combined Cycle (IGCC)

Comment:

CFB boilers do not achieve emission levels comparable to IGCC. When compared to IGCC, CFB boilers come in worse across the board for numerous pollutants. For example, CFB boilers and IGCC do not achieve comparable NO_x emissions rates. CFB boiler permit levels for NO_x have generally been in the 0.07 to 0.08 lb/MMBtu range. In contrast, expected NO_x emissions levels for recently proposed IGCC plants averaged 0.039 lb/MMBtu. NO_x levels from IGCC, therefore, are upwards of 45% lower than CFB boilers. IGCC facilities are similarly lower in SO₂ emissions, with 30-day averages at nearly half that proposed for the present CFB boilers (0.033 lb/MMBtu for IGCC versus 0.06 lb/MMBtu for the Proposed Coal Plant). PM₁₀ emissions from IGCC also are significantly lower than for the Proposed Coal Plant.

Response:

The MDEQ required an evaluation of IGCC as part of the BACT analysis for the proposed facility. On February 25, 2008, Wolverine submitted to MDEQ additional information to supplement the permit application for the IGCC BACT analysis pursuant to the agency's information request of February 14, 2008. Based on the MDEQ's review of Wolverine's submittal, and the comments received, the MDEQ determined that the cost of IGCC is excessive (approximately \$26,000 per ton of emissions removed for the criteria pollutants) and that IGCC is not BACT for the proposed facility.

The BACT analysis considered the total annualized costs for IGCC versus the CFB boilers in calculating the costs per ton of criteria pollutants removed. The high cost of IGCC is due in part to the substantial difference in the costs of engineering, procurement and construction (EPC) between IGCC and the proposed. Wolverine identified a 37.2% higher EPC cost (i.e., a premium) for a 600 MW IGCC to generate the electricity Wolverine seeks.

In responding to the emission rates that can be achieved by an IGCC facility, MDEQ concurs that for certain pollutants, an IGCC facility would emit at a lower rate. However, this does not alter the overall MDEQ conclusion that IGCC is cost prohibitive.

It is worth noting that in comparing emissions and costs of similar facilities, such as those presented by the commenter, the facilities, although permitted, have not been constructed. No verification of emission rates through stack testing has occurred. In addition, the two known operating IGCC facilities in this country located at Wabash, Indiana and Polk Unit 1, Tampa, Florida, both had large portions federally funded by the Department of Energy (DOE). A comparative evaluation of costing techniques is not reflective of true costs of the project.

In summary, the MDEQ reviewed the detailed IGCC analysis submitted by Wolverine and accurately concluded that IGCC is cost prohibitive in terms of the cost to remove a ton of criteria pollutants.

2. Clean Fuels

Comment:

MDEQ and the applicant failed to consider clean fuels and low sulfur coal in the BACT analyses. A permittee cannot avoid lower emission limits achievable with cleaner fuels based on its desire for "fuel flexibility". The applicant and MDEQ may only justify rejecting the top control (cleanest fuel) on other environmental grounds in a proper collateral impacts analysis, including quantification of impacts to the extent possible. The boiler is not limited to the dirtiest fuels but rather it is capable of burning a range of fuels, including those that release comparatively less pollution.

Response:

In the original application, Wolverine submitted a Fuel Supply and Fuel Selection Study dated November 2007 as prepared by Burns and Roe Enterprises which was performed to identify fuels that would be appropriate for the WCEV project. In response to public comment and at the request of the MDEQ, Wolverine submitted additional information on their evaluation of clean fuels. This document titled 'Fuel BACT Review' is dated June 22, 2009. The Fuel BACT Review supports the fuel selection by Wolverine as representing BACT.

Because the chosen CFB boiler technology is designed to burn multiple fuels, it is appropriate for MDEQ to evaluate Wolverine's request to use up to 70% pet coke to blend with western PRB coal, while reserving the ability to utilize 100% PRB, ILB coal, or 20% biomass with 80% PRB. It is also appropriate for MDEQ to evaluate other, 'cleaner,' fuels as well. In making this evaluation, MDEQ accepted the approach by Wolverine to start with a base case of the chosen boiler and control technology, comparing other 'cleaner' fuels against the selected fuels.

The Fuel BACT Review identified the fuel options, including 'cleaner' fuels, available to the WCEV project and how the availability of such fuels is related to the transportation resources available to the site as well as the emission unit under consideration. The emissions characteristics and available control technology are dependent on the boiler type. Therefore, in addition to considering fuel type, the CFB boiler technology itself must be taken into account. The decision on which generating technology to select was based on considerations such as the desired generating capacity, planned use of the capacity in meeting load, fuel type, transportation, transmission, and water and raw material resource availability. Wolverine selected a CFB boiler which can best accommodate western sub-bituminous coal (Powder River Basin), eastern bituminous coal (Illinois Basin), central

bituminous coal (Central Appalachia & Northern Appalachia), western bituminous coal (Western Canada), pet coke, and biomass. Other fuels, such as natural gas, fuel oil, and biomass used as primary fuels, may require significant boiler modification and/or new boiler design.

Of the coals under consideration for use in a CFB boiler, the average coal prices were compared by region, taking into account availability, long term stability, and transportation costs, and the more economic coals were chosen. The remaining coals were put through a coal/ash characterization and were screened using critical fuel characteristics including; fuel heating value, sulfur content, ash content, chlorine content, ash fusion temperature, sodium in ash, and mercury in coal. The fuels meeting the necessary criteria were: PRB, Illinois Basin, pet coke, and biomass. Wolverine has proposed to burn western (PRB) sub-bituminous coal with a blend of up to 70% petroleum coke as its primary fuel, and ILB as a secondary fuel. The project's location within a limestone quarry greatly diminishes the cost impact of using high sulfur fuels because the limestone is very inexpensive, readily available, and can be used as a reagent to capture SO₂ in the CFB boiler furnace. According to the Fuel Supply and Fuel Selection Study, burning 100% PRB coal or ILB coal are also both available options and are technically feasible.

It is generally known that the cost of coal is related to the heat content in the coal, *i. e.*, the greater the heat content, such as in eastern coal, the more costly the price of this coal. Heat content is the amount of energy that can be generated from a fuel and is reported as MMBtu. Wolverine has stated that there is no business advantage to use eastern coal, as pet coke and western coal delivered costs are less expensive at \$1.32 per MMBtu and \$1.91 per MMBtu, respectively. Eastern coal has a delivered cost of \$2.17 per MMBtu. The fuel user (Wolverine) can mitigate the risks of unforeseen circumstances in the chosen fuel supply by using fuel flexibility/blending. Examples of such a circumstance would be a rail disruption or mine strike which reduce or interrupt supply. The proposed blend of up to 70% pet coke blended with PRB allows Wolverine to mitigate price fluctuations and maintain supply and transportation reliability. Limiting a base load facility to a single fuel supply source is a risk both from a financial and reliability perspective.

Wolverine conducted the Fuel BACT Review taking into consideration the add-on control equipment selected as BACT. BACT for this project includes the inherent CFB boiler control and polishing scrubber for SO₂, SNCR for NO_x, a baghouse for PM₁₀, the polishing scrubber and baghouse for PM_{2.5}, and good combustion control for CO and VOC. A pollutant by pollutant review was then conducted to determine if a cleaner fuel would be considered BACT. Costs of fuel switching were considered as compared to the base case or in terms of burning western (PRB) sub-bituminous coal with a blend of up to 70% petroleum coke.

The sulfur content of the fuel is directly related to SO₂ generation which is the dominant pollutant in terms of fuel choice. The PRB coal is known to have lower sulfur content than other coals. The typical sulfur content of PRB coal ranges from 0.2 – 1.0%, while ILB ranges from 1.0% to 3.0%. While the sulfur content of pet coke is higher than coal, ranging from 4.0% to 7.0%, it is not necessarily a poor choice of fuel. Pet coke burned in a CFB boiler with the inherent control via the limestone bed along with the add-on polishing scrubber, results in similar outlet SO₂ emissions as other boilers burning coal. The CFB boiler design provides an inherent control as the limestone bed reacts with the sulfur in fuel to provide a removal efficiency of up to 80%. In general, pet coke has a lower ash content (<0.5%), lower moisture content (8-10%) and lower volatiles (8-10%) than coal, resulting in a much higher

heat content, on the order of 14,000 Btu/lb. In comparison, the heat content of PRB ranges from 8,500 to 9,500 Btu/lb. A higher heat content results in less pet coke needed to achieve the same energy level.

The sulfur content of biomass varies, depending of the type of wood, from 0.01% to 0.10%. The boiler is limited in the amount of biomass it can burn. According to the Fuel BACT Review "Biomass combustion is limited by the amount of biomass in the region and the fuel characteristics of the biomass. It has been determined that a maximum of 20% of the boiler heat input can be provided by biomass." In addition, biomass has the lowest heat content of the fuels considered resulting in more biomass burned to achieve the same amount of energy as coal or pet coke. The heat content of biomass ranges from 4,000 to 7,000 Btu/lb, depending on the moisture content. Biomass with a higher moisture content can affect flame stability in the boiler and could lead to increased CO emissions. A balance of fuels will assure consistent characteristics in the boiler. The chosen fuel blends will meet the 0.05 lb SO₂ per MMBtu, based on an annual average and 0.06 lb SO₂ MMBtu 30 day rolling average, limits identified as BACT.

NOx emissions result from both fuel bound nitrogen as well as a result of combustion (i.e. thermal NOx). NOx formation is related to temperature. Because a CFB boiler operates at a lower combustion temperature than more traditional boilers, thermal NOx formation is less significant, making fuel NOx the dominant contributor. Of the fuels reviewed, the Fuel BACT Review concluded that with the inherent limitations of the SNCR system (i.e. ammonia slip), no fuel identified for review provides an advantage over another in terms of NOx formation or control.

The Fuel BACT Review concluded that PM10 and PM2.5 emissions are not affected by the fuel choice as it has been defined by Wolverine. Emission differences between coal types, pet coke and biomass are not significant as they will be controlled by the baghouse which is designed to remove in excess of 99% of the particulate that passes through, independent of the inlet loading.

CO and VOC are products of combustion, formed when fuels are not combusted completely. BACT for CO and VOC is good combustion. CO may be impacted by use of biomass as wood has higher moisture content and driving this moisture off may affect boiler temperature, thereby increasing CO. A well operated boiler will maintain the temperature in the CFB boiler to optimize combustion. Biomass has benefits as a clean fuel in that it has a lower sulfur and mercury content and is a renewable resource. However, the boiler is limited in the amount of biomass it can burn based on concerns over being able to support its use on a sustainable basis.

The MDEQ also evaluated use of natural gas as a fuel. Natural gas use was addressed in the Fuel Supply and Fuel Selection Study as well as in the Electric Generating Alternatives Analysis (EGAA), dated June 8, 2009. Natural gas was not pursued as a viable fuel for long-term energy production due to the price volatility. The price of natural gas is referenced in the EGAA. The following table is an excerpt from the EGAA comparing natural gas costs to PRB and pet coke. As the data supports, natural gas is at least 5 times greater in price than coal. In addition to the fuel volatility, when assessing costs for a natural gas plant, the addition of a natural gas pipeline to bring suitable natural gas quantities for base load generation to the Rogers City site must be factored in. It would be cost prohibitive to construct the necessary infrastructure to get natural gas to the plant site.

Wolverine Screening Curve Fuel Cost Input (\$/MMBtu)

Fuel	Low Fuel Cost	High Fuel Cost
Natural Gas	\$6.15	\$13.40
PRB Coal	1.20	4.56
Petroleum Coke	1.00	4.00

Based on these considerations, MDEQ has determined that burning western (PRB) sub-bituminous coal with a blend of up to 70% petroleum coke as primary fuel, and ILB as a secondary fuel provides "fuel flexibility to manage fuel supply risks" and is a reasonable consideration in the BACT process.

Comment:

Including BACT limits based on the cleanest fuel or combination of fuels proposed by the applicant is not redefining the source. The proposed plant is specifically designed to burn a range of fuels, including low sulfur PRB sub bituminous coal, higher sulfur Illinois bituminous coal, very high sulfur pet coke, and low sulfur biomass. Basing BACT limits on the cleanest fuel or combination of fuels proposed by the applicant is not redefining the source.

Response:

Given the design of the boiler and furnace, Wolverine determined that the CFB boiler could accommodate, with little or no modification to the burner configuration, western sub-bituminous coal (Powder River Basin), eastern bituminous coal (Illinois Basin), central bituminous coal (Central Appalachia & Northern Appalachia), western bituminous coal (Western Canada), pet coke, and biomass. The Fuel BACT Review addressed these fuels and concluded which fuels represent BACT. Other fuels, such as natural gas or biomass used as primary fuels, may require significant boiler modification and/or new boiler design. The MDEQ concurs with the Fuel BACT Review submitted by Wolverine in selecting to burn western (PRB) sub-bituminous coal with a blend of up to 70% petroleum coke as its primary fuel and ILB as a secondary fuel.

Comment:

The claim that Wolverine could not burn clean fuels rings hollow. CFB boilers are capable of burning a wide range of sulfur content fuels.

Response:

MDEQ agrees with the statement that CFB boilers are capable of burning a wide range of fuels. In fact, Wolverine has proposed to burn western (PRB) sub-bituminous coal with a blend of up to 70% petroleum coke as its primary fuel and ILB as a secondary fuel. The CFB boiler is also being designed to burn up to 20% biomass. The issue of clean fuels was addressed in the June 9, 2009 Fuel BACT Review and Appendix 2, Fuel Supply and Fuel Selection Study. MDEQ concurs with the conclusions drawn by Wolverine that the selected fuel mix represents BACT.

Comment:

Fuel choice is relevant to BACT for several regulated NSR pollutants. The applicant rejects the lowest permitted SO₂ emissions rates from the AES-Puerto Rico & NEVCO Sevier plants on the basis that neither is designed to utilize pet coke.

Response:

MDEQ reviewed both AES Puerto Rico and NEVCO Sevier as part of the permit review and concluded that emission limits established as BACT for these two facilities were not comparable to the Wolverine proposal. Both AES Puerto Rico and NEVCO Sevier proposed to burn low sulfur coal. Wolverine proposed to burn western (PRB) sub-bituminous coal (a low sulfur coal) with a blend of up to 70% petroleum coke as its primary fuel, and ILB as a secondary fuel. A CFB boiler can accommodate many different fuels. As stated in the AES permit, permit values identified in the AES permit were based on the 'environmentally worst-case coal' allowed by the permit, which in this case was 1% sulfur coal. In the case of Wolverine, permit values were also based on the 'environmentally worst-case fuel' which in the case of Wolverine was pet coke. Neither AES Puerto Rico nor NEVCO Sevier is permitted to burn pet coke or higher sulfur coal.

Fuel selection is critical to establishing emission limits. Wolverine has demonstrated through the Fuel BACT Review that their selected fuel blend of western (PRB) sub-bituminous coal with a blend of up to 70% petroleum coke as its primary fuel and ILB as a secondary fuel represents BACT. A BACT analysis evaluates multiple criteria, including costs, to determine the appropriate emissions control strategy for the proposed project. Costs of burning a lower sulfur fuel or fuel blend were compared incrementally against the Wolverine selected fuel blend and determined to be excessive.

The cost per year of burning PRB (alone), Biomass/PRB blend, or IB alone were compared to the Wolverine selected fuel blend and determined the difference, respectively, as follows: \$7,414,697; \$17,676,785; and \$15,546,348.

The MDEQ concurs with the Fuel BACT Review submitted by Wolverine in selecting to burn western (PRB) sub-bituminous coal with a blend of up to 70% petroleum coke as its primary fuel and ILB as a secondary fuel.

For comparison purposes, the emission limits for the AES Puerto Rico and NEVCO Sevier facilities are identified below:

<i>Pollutant</i>	<i>Wolverine</i>	<i>AES Puerto Rico</i>	<i>JEA Northside</i>	<i>NEVCO Sevier</i>
<i>SO2</i>	<i>0.06 (30-day), 0.05(12month), 303 pph (24-hr)</i>	<i>0.022 (3-hr)</i>	<i>0.15 (30 day), 0.20 (24-hr)</i>	<i>0.022 (30-day), 0.05 (24-hr)</i>
<i>NOx</i>	<i>0.07 (30-day), 281.1 pph (24-hr)</i>	<i>0.10 (24-hr)</i>	<i>0.09 (30-day)</i>	<i>0.1 (24-hour)</i>
<i>H2SO4</i>	<i>0.003 (24-hr)</i>	<i>0.0024 (24-hr)</i>	<i>1.1 pph</i>	<i>0.0024 (24-hr)</i>
<i>PM</i>	<i>0.010</i>	<i>0.015 (24-hr)</i>	<i>0.011</i>	<i>0.0154** (24-hr)</i>

<i>PM10</i>	<i>0.026, 78.8 pph</i>	<i>0.015 (24-hr)</i>	<i>0.011 **</i>	<i>0.0154** (24-hr)</i>
<i>CO</i>	<i>0.15 (30-day), 744 pph (24-hr)</i>	<i>0.10 (8-hr)</i>	<i>0.22 (24-hr)</i>	<i>0.115 (1-hr)</i>
<i>All limits are in units of lb/MMBtu, unless otherwise noted. **Limit is listed in the permit as PM/PM10.</i>				

Comment:

The BACT limits for sulfuric acid mist (SAM) and PM2.5 must consider use of low sulfur fuels.

Response:

Both SAM and PM2.5 were subject to a BACT review. The issue of low sulfur fuels was addressed by Wolverine in the Fuel BACT Review. After a thorough top-down BACT review, taking into account 'clean' fuels, SAM and PM2.5 limits as proposed in the Wolverine permit are 0.003 lb/MMBtu and 0.024 lb/MMBtu, respectively. The MDEQ concurs with the Fuel BACT Review submitted by Wolverine in selecting to burn western (PRB) sub-bituminous coal with a blend of up to 70% petroleum coke as its primary fuel and ILB as a secondary fuel.

Comment:

The amount of particulate matter and NOx are also dependent on the fuel source. Combustion of biomass generally results in lower PM and NOx emissions than coal.

Response:

As for the use of biomass in establishing particulate and NOx limits, the amount of particulate and NOx emissions from biomass use is dependent on the type of biomass. A decrease in NOx based on a lower operating temperature may result in an increase in CO. Particulate may or may not decrease with use of biomass. In any case, the BACT limits established for NOx and particulate are appropriate and are in line with similar facilities burning a similar fuel combination. After a thorough top-down BACT review, taking into account 'clean' fuels, particulate and NOx limits as proposed in the Wolverine permit are 0.010 lb/MMBtu (PM10 limit is 0.026) and 0.07 lb/MMBtu, respectively. The MDEQ concurs with the Fuel BACT Review submitted by Wolverine in selecting to burn western (PRB) sub-bituminous coal with a blend of up to 70% petroleum coke as its primary fuel and ILB as a secondary fuel.

Comment:

Throughout the draft permit, the applicant emphasizes fuel flexibility as a benefit of CFB boiler technology. The prospect of a more diverse fuel stream brings responsibility to thoroughly characterize the additional potential emissions profiles and their impacts on human health and natural resources. This responsibility was not met in the draft permit. Until a comprehensive analysis of all possible emissions profiles is provided, the draft permit must be considered incomplete.

Response:

All fuel streams were evaluated and to be conservative (as to not exceed any regulation standards) pollutants showing the highest emissions were evaluated and compared to all

state and federal regulations. Impacts on human health were thoroughly reviewed and results of the MDEQ analysis can be found in Section C. Public Health and Environmental Concerns.

Comment:

No where in the document is the term "biomass" specifically defined. Any wood waste should be prohibited that has been painted or chemically treated.

Response:

Biomass is defined in the permit, special condition II.3, Material Limits for FGCFB, and does not include materials from building construction or demolition. Painted or chemically treated wood is also prohibited. Biomass is defined as non-chemically treated wood and wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, processed pellets made from wood or other forest residues, switch grass, and other similar fuels.

Comment:

MDEQ failed to evaluate emissions from biomass fuel hauling. A thorough analysis of emissions from biomass freight operations must be conducted. Key parameters in the analysis should include quantities of various biomass feed stocks consumed, and average duration and number of truck trips needed to deliver it to the plant. Until a comprehensive analysis of all possible emissions profiles is provided, the draft permit must be considered incomplete.

Response:

Emissions from the use of biomass as a fuel have been evaluated as part of this application review. Roadways and associated truck traffic emissions are covered by the Fugitive Emissions Control Plan (FECP). Due to the variable nature of the biomass fuel industry it is not known at this time if WCEV will be processing biomass prior to combustion or receiving pre-processed biomass. Off-site freight operations are beyond the regulatory authority of the air permit evaluation.

Comment:

The BACT analysis is deficient because it did not consider the impact of fuel choice on start up and shut down emissions. BACT during start up and shut down should require the maximum amount of biomass feasible and an accompanying reduction in low sulfur coal.

Response:

Fuels were considered in the BACT analysis for periods of startup and shutdown and limits were appropriately established. Depending on the nature (i.e. cold start, warm start) and duration of the startup, NO_x and SO₂ can be significantly higher during start up and shut down than during normal operation. The SO₂ and NO_x control equipment requires stable boiler conditions for effective operation. Effective operation of the SNCR to control NO_x emissions requires stable flue gas flows and temperatures greater than 1,500°F to ensure that the injected ammonia reacts with the NO_x in the flue gas. Otherwise, ammonia slip can occur which can contribute to additional particulate emissions. Effective operation of the polishing scrubber to control SO₂ emissions, is much the same. Ensuring the proper bed temperature, mixing, availability of bed lime for SO₂ absorption, and operation of the spray

dryer absorber (SDA) for SO₂ control can all affect higher than normal SO₂ emissions. Therefore because the control equipment is not fully operational during startup #2 fuel oil with 0.05% sulfur, low sulfur coal, and/or biomass will be utilized in the CFB boilers. NO_x and SO₂ are inherently lower in those fuels as opposed to the PRB coal and pet coke. After the boiler(s) reaches about 40% load, and the control equipment is operating effectively, then PRB coal and pet coke will begin to be added.

This scenario was determined by MDEQ to represent BACT and BACT emission limits were appropriately set to account for periods of start up and shut down.

Comment:

As part of the BACT determination, Wolverine must consider the collateral impacts from fuel choice including the volume of ash that will be produced, the amount that will be sold for reuse, the amount that will require landfill disposal including disposal costs, as well as the expected content of the ash.

Response:

In the Fuel BACT Review analysis, Wolverine addressed the volume of ash, disposal of the ash, and the cost of disposal. MDEQ reviewed this analysis and determined it to be acceptable.

Comment:

Has anyone considered blending anthracite coal with bituminous coal?

Response:

Blending anthracite coal with bituminous coal was not considered for this project.

Comment:

What is petroleum coke? What are the benefits of its use? What are the risks? Mercury, acids, particulates, HAPs, and other emissions based on 100% sub bituminous, 100% Illinois coal, and up to 70% pet coke, 20% biomass, need further consideration. Examples given at other facilities burning pet coke show increased emissions over coal for several pollutants. Given that substantial dirty tar sand oil is presently being refined at locations on the Great Lakes, it should be presumed that pet coke waste from this heavy oil would be even more contaminated, especially with sulfur and heavy metals.

Response:

Petroleum coke, often referred to as pet coke, which is defined as a solid derived from oil refinery coker units or other cracking (breaking long chain hydrocarbons into short ones) processes. This by-product once disposed of in landfills, is now used in the cement industry and utility plants as fuel and raw materials. There are many benefits to using petroleum coke as a fuel. It makes a good source of fuel because less fuel is needed on a pound of fuel per million Btu basis as compared to coal. Other benefits include, low ash content, lower cost per ton, and lower mercury content, as compared to coal. The low ash content means there are less emissions of particulate matter. There are no risks to using petroleum coke, although one disadvantage is it contains a high sulfur content, as compared to coal. However, with the proper add-on control technology to control SO₂ emissions, like those that Wolverine has proposed, it is still a good source of fuel for a relatively low price compared

with coal. The source of petroleum coke that Wolverine is proposing has not yet been determined. All petroleum coke emissions evaluated were based on the Louisiana Cleco Corporation application, in which the facility was permitted to burn 100% petroleum coke.

Comment:

How can Wolverine use up to 70% pet coke as a fuel, when they do not have a local permit to burn pet coke?

Response:

The state requirements contained in the air permit to install are based on state regulations the facility must meet. Those requirements are separate from any local requirements such as zoning or special use permits.

Comment:

Commenter requests that for MDEQ to make public all data used to justify the economic decisions that are contained in this permit. Show the math where there are economic decisions used to drive environmental decisions within this permit.

Response:

All supporting information used in reviewing the permit application is contained in the permit file and is available by the Freedom of Information Act, including the economic analysis in the BACT review. In addition, Wolverine's submittals were made available on the MDEQ AQD website at <http://www.deq.state.mi.us/aps/downloads/permits/cfpp/cfpp.htm>.

3. Opacity

Comment:

The draft permit does not contain a BACT limit for opacity from the boiler.

Response:

The draft permit contains a limit of 10 percent, based on a 6-minute average, except one 6-minute average per hour of not more than 20 percent. MDEQ considers this BACT.

4. PM2.5

Comment:

The MDEQ's application of EPA's surrogate policy for PM10 does not satisfy the legal requirements of the CAA for PM2.5. PM2.5 is a regulated new source review pollutant that the proposed facility will emit in significant amounts. The MDEQ must therefore establish BACT emission limits for PM2.5.

Even if the PM10 surrogate policy is lawful, it is no longer appropriate because the technical difficulties on which it is based (PM2.5 monitoring, emissions estimation and modeling) have been resolved.

Response:

A PM2.5 BACT analysis was submitted by Wolverine on September 30, 2008 and additional supporting information was submitted on June 22, July 27 and July 29 of 2009. Wolverine

also submitted an air quality analysis that includes a modeling demonstration showing that emissions from the proposed facility will not exceed the NAAQS or PSD increments for PM2.5. MDEQ held a public comment period from August 18, 2009 through September 17, 2009 with an informational meeting and hearing held on September 17, 2009 to incorporate the PM2.5 BACT limits, stack testing, and monitoring requirements into the draft permit.

Comment:

The late submitted PM2.5 BACT analysis supplement is flawed in numerous ways.

- 1) The analysis does not discuss the baghouse design basis and membrane bag technology in sufficient detail in order to determine the removal efficiency.
- 2) The analysis only considered a wet ESP and a fabric filter baghouse as control technologies. The analysis should of included other options to reduce PM2.5 emission such as an "Advanced Hybrid Particulate Collector" (AHPC) system.
- 3) The analysis should be more like the Highwood Generating Station BACT analysis where they considered various types of control technologies individually and in combination with each other.
- 4) Test data from the Manitowoc Public Utilities facility is achieving a PM10 level of 0.0210 lb/MMBtu as BACT for PM2.5. This limit is less than half the limit Wolverine is proposing as BACT for PM2.5.

Response:

MDEQ disagrees with the above comments.

The additional information Wolverine submitted on July 27, 2009 gives a thorough explanation of the filterable and condensable portions of the PM2.5 emission rate proposed from the CFB boilers. Since reliable emissions information on PM2.5 is still limited, it is difficult to determine what the removal efficiency will be. Although some vendors have provided estimates, it is still not known how reliable the data is. Therefore, Wolverine took a conservative approach in which they assumed that approximately 80% of filterable PM10 (or 0.008 lb/MMBtu) best represented the expected filterable PM2.5 emissions. For the condensable portion of PM2.5, Wolverine assumed that it would be equally proportional to PM10 condensable emissions (or 0.016 lb/MMBtu).

Wolverine considered many control technologies in their BACT review, as the record demonstrates. The commenter listed several technologies related to ESP technologies that have not been demonstrated in practice. (Table 1 in the July 27, 2009 submittal discusses where the various technologies can be found in the record.) MDEQ recognizes the technologies listed by the commenter. However, these technologies were deemed to be infeasible since it is not clear what effect (those technologies) would have on acid gases and mercury. WESP, ESP, fabric filter baghouse with membrane bags, and fabric filter baghouse with felted polyphenylene sulfide (PPS) bags were evaluated as the top controls for PM2.5.

The commenter references the Otter Tail Power's Big Stone plant in South Dakota where the AHPC system was used for a retrofit project. That AHPC system failed and was replaced with a pulse jet baghouse.

Wolverine did evaluate particulate control technologies in combination with other particulate control devices, as did the Highwood Generating Facility. The record reflects a cost analysis, done by Wolverine, in series for a polishing scrubber, baghouse, and wet ESP. After an iteration of such an analysis, it was found that as the additional control technologies are added to the series and the removal efficiency approaches zero, the cost is beyond economical. Also note, the Highwood analysis, determined that the source would install a FGD (polishing scrubber) followed by a fabric filter baghouse for BACT of PM_{2.5} but does not establish a BACT emission limit.

The Manitowoc Public Utilities CFB boiler has a limit of 0.03 lb/MMBtu for total particulate. Stack test results for one day, while firing coal only, demonstrated the following emission rates: PM total = 0.0120, PM condensable = 0.0092, and calculated PM Filterable = (0.012 – 0.0092) = 0.0028. The stack test data does not demonstrate that there was a Method 202 for PM filterable done. AQD disagrees that this one stack test for PM should be used as a basis for setting a limit for PM_{2.5}. The stack test was done for PM total and PM condensables, only. There was no test done for PM_{2.5}, and therefore the MDEQ believes that setting a limit based only on PM condensable does not provide enough supporting data to demonstrate such a limit would be achievable.

5. PM₁₀

Comment:

First, the limit on PM₁₀ fails to include condensable particulate matter. A BACT limit on PM must include the condensable portion. While MDEQ claims the PM₁₀ limit includes both filterable and condensable PM, the limit is not accompanied by any testing requirements that include the condensable portion. Rather, compliance with the limit is determined only by stack test. The PM₁₀ BACT limit must be based on a test method like Method 202 that includes the condensable portion.

Response:

Particulate matter (PM) is defined by MDEQ, Air Pollution Control Rule 336.1116(c), "Particulate matter" means any air contaminant existing as a finely divided liquid or solid, other than uncombined water, as measured by a reference test specified in R 336.2004(5) or by an equivalent or alternative method. This means that determinations of particulate emission rates for stationary sources shall be conducted as specified in the following reference test methods: 5, 5B, 5C, 5D, 5E, or an acceptable alternative method. Acceptable test methods measure filterable particulate emissions.

PM₁₀ is defined by MDEQ, Air Pollution Control Rule 336.1116(k), "PM₁₀" means particulate matter that has an aerodynamic diameter less than or equal to a nominal 10 micrometers, as measured by a reference test specified in 40 C.F.R. Part 51, Appendix M. The reference test methods include 201 (filterable) and 202 (condensable). Acceptable test methods measure filterable particulate and condensable particulate to determine PM₁₀ emissions.

Both PM and PM₁₀ are required to be measured to show compliance with the emission limits in the permit. In order to establish uniform requirements to help ensure proper test methods and procedures are used for the compliance demonstration, a complete test plan is required to be submitted to the appropriate AQD district office and the Technical Programs Unit in

Lansing, at least 60 days prior to the scheduled test date. A complete submittal will minimize the possibility of a test rejection as a result of improper sampling or data collection methods. Testing shall be performed in strict accordance with the procedures specified in 40 CFR Part 60 (Standards of Performance for New Stationary Sources, Appendix A, as amended), Part 61 (NESHAP, Appendix B), and Part 51 (Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Appendix M); and the MDEQ Rules, Part 10, Intermittent Testing and Sampling. Any variations in the sampling or analytical procedures must be described in the test plan and receive approval from the AQD prior to testing. If state or federal test methods are not available for the pollutants of concern, or the nature of the test site makes it impractical to use them, other methods may be proposed as necessary.

Comment:

The Draft Permit proposes as BACT for PM and PM10, through the use of a fabric filter, the following emission limits: 0.010 lb/MMBtu for PM and 0.026 lb/MMBtu for PM10. This is not BACT for the PM.

BACT is 0.0088 lb/MMBtu for total PM emissions. Pennsylvania issued a PSD permit in April 1995 to the Northampton Generating Company with a total PM10 limit of 0.0088 lb/MMBtu. This facility burns anthracite culm in a 1,146 MMBtu/hr circulating fluidized bed boiler. Compliance testing in February 2001 reported total PM10 emissions of 0.0045 lb/MMBtu. The permit limit and the compliance tests for Northampton have been rejected by other permitting agencies in the past due to those agencies' confusion as to whether the 0.0088 lb/MMBtu Northampton permit limit includes condensable PM. The confusion appears to stem from the fact that the Northampton permit requires testing by "Method 5." USEPA Method 5 tests only for filterable particulate matter. However, the "Method 5" referred to in the Pennsylvania DEQ Permit for Northampton refers to Pennsylvania Method 5, which includes both front half and some condensable (backhalf) emissions (i.e., both filterable and condensable PM). The Pennsylvania permit and compliance tests for Northampton included condensable fraction PM in the backhalf of the control train.

A test at the JEA facility, conducted by Black & Veatch for the Department of Energy, measured filterable PM emissions of 0.004 lb/MMBtu. This is significantly lower than the proposed 0.010 lb/MMBtu for PM and 0.026 lb/MMBtu for PM10.

Response:

MDEQ disagrees with the commenter. MDEQ reviewed Wolverine's BACT analysis and determined that BACT for the CFB boilers was 0.010 lb/MMBtu for PM, 0.026 lb/MMBtu and 78.8 pph for PM10.

The stack test for Northampton Generating Company was reviewed by the MDEQ-AQD Technical Programs Unit, and determined to be incorrect for measurement of PM10 emissions. Instead of drying and weighing the impingers to get back half condensable PM, they filtered the impinger liquid and only dried and weighed the filter. The majority of the condensable PM would be dissolved in the impinger liquid and run through the filter. Northampton did not find any condensable PM when testing the anthracite coal boiler and the reported total PM10 emissions of 0.0045 lb/MMBtu is bias low. This test data does not support setting a limit for PM10 that is lower than proposed since the test method did not measure condensables appropriately.

PM emission tests for the JEA facility have varied up to as high as 0.0091 lb/MMBtu filterable PM in November 2002, while burning 75% petroleum coke and 25% coal (a blend very close to that identified by Wolverine as its "design fuel"). JEA Northside has demonstrated lower particulate emission rates under a variety of operating conditions. It has also demonstrated that a limit of 0.004 lb/MMBtu can not be achieved continuously using the same monitoring methods that Wolverine will be using. The proposed PM BACT limit of 0.010 lb/MMBtu contains an acceptable factor of safety that would assure continuous compliance.

Comment:

The PM limit is not BACT because compliance is not measured by a continuous emission monitoring system for PM ("PM CEMS"). The method of determining compliance is a critical part of a permit limit, which impacts the stringency of the limit. Here, the Draft Permit requires that compliance with the PM/PM10 limit be demonstrated by stack testing and continuous opacity monitoring. The permit for Spurlock Unit 4 requires that PM CEMS be used to demonstrate compliance with the PM (filterable) BACT limit. The record contains no information showing why PM CEMS cannot be used to demonstrate compliance at the Proposed Coal Plant.

Response:

Currently, a PM CEMS is not required by any federal or state regulation. Wolverine has proposed to demonstrate compliance with the PM BACT limit through periodic stack testing, and a continuous opacity monitoring system (COMS). A COMS indicates the presence of particulate matter, and will provide an indication of continuous satisfactory operation of the boilers when an opacity of less than 10 percent is met. A COMS is also allowed as a compliance provision per 40 C.F.R. 60, Subpart Da to monitor the performance of a fabric filter operated to comply with the applicable PM emission limit. A COMS is an acceptable monitoring system on a PSD permit.

6. NOx

Comment:

The MDEQ notes that SCR can control NOx emissions by 80-90% efficiency. This underestimates the efficiency. Recent SCRs, designed for high-dust (located upstream of the particulate control device) coal boiler applications routinely achieve greater than 90% NOx reduction.

Response:

MDEQ agrees that SCRs, can likely reach efficiencies greater than 90% for NOx reduction. However, maintaining that efficiency is not usually practical from a cost standpoint. Also, the MDEQ is not aware of any CFB boilers with SCR control that have demonstrated greater than 90% and the commenter did not give any examples of such sources.

Comment:

Due to numerous errors in assessing selective catalytic reduction ("SCR") and selective non-catalytic reduction ("SNCR"), MDEQ failed to base BACT on the top control technology. In conducting its BACT analysis, Wolverine evaluated several NOx control approaches, as summarized in the MDEQ Fact Sheet. These included staged combustion techniques, flue

gas recirculation, SCONOx™, gas reburn, SNCR and SCR. The discussion of SCR is deficient and the rejection of SCR is without basis: the analysis of the technical feasibility of upstream SCR is flawed, while the analysis of the economic feasibility of downstream SCR contains improper data and assumptions. Finally, the control technology—SNCR—and NOx limit selected is not BACT.

MDEQ erred in dismissing the technical feasibility of upstream SCR in a “high dust” setting. In addition, MDEQ made the statement that SCRs have not been demonstrated to be technically feasible on CFB boilers, and Wolverine’s assertion that SCR has “never been installed on a CFB boiler in a high dust location”, are both inapplicable to the BACT discussion and patently untrue.

Response:

Using the top-down BACT approach per EPA’s DRAFT New Source Review Workshop Manual (October 1990), SCR was identified as the top control option for NOx. However, the BACT analysis takes into account energy, environmental, and economic impacts and other costs to determine if the maximum degree of reduction is achievable for a source. The technical feasibility and the cost of an SCR for a CFB boiler was thoroughly investigated.

Documents published by EPA, EPA/452/B-02-001 and EPA-452/F-03-032, do support the claim that using SCRs in high dust locations will result in fouling of the catalyst. Therefore, MDEQ did find that the location of a SCR in high dust locations to be technically infeasible.

MDEQ believes the use of SNCR is BACT for NOx and was determined using the top-down BACT approach. As determined in the Sierra Club vs. Western Greenbrier Co-Generation, LLC, (Appeal # 06-03-AQS) the permittee was not required to innovate or to push technology beyond what is available and applicable. EPA’s DRAFT New Source Review Workshop Manual (October 1990), page B.18, states that in determining the technical feasibility of “available” control technologies:

“[a] source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new or dissimilar source type.”

Wolverine initially submitted SNCR with tail-end cold-side (located after PM and sulfur removal equipment) SCR, however they excluded SCR saying it was not feasible. The AQD disagreed and asked Wolverine for an additional analysis based on tail-end SCR without SNCR, in December 2007. Wolverine provided supplemental information supporting tail-end SCR as not cost effective. The cost effectiveness of this control technology was approximately \$20,100 per ton (for both boilers uncontrolled emissions), which was considered cost prohibitive. An SCR located after other control equipment requires the flue gas to be reheated for proper operation and NOx removal efficiency which increases the costs associated with this option.

Comment:

Operation of SCR also will result in reductions in dioxins. The Proposed Coal Plant is subject to MACT for dioxins. The current MACT limits fail to control dioxins adequately. An SCR is one technology that can be used to establish more appropriate MACT limits. Therefore, the

cost effectiveness of SCR must be credited with reduction of dioxins, a result not seen with SNCR.

Response:

This source is not subject to MACT limits. The proposed project is subject to 112(g), which effectively evaluated all Hazardous Air Pollutants (HAP).

Comment:

The control technology analysis of SNCR is faulty. MDEQ cited permits that have to meet limits at all load conditions, unlike Wolverine.

MDEQ 's analysis of other facilities NOx emissions is disingenuous. They noted several facilities that had NOx emissions of 0.07 lb/MMBtu, the MDEQ does not include that these permits require the limit to be met at all load ranges.

There are several other existing coal fired CFB boilers that have NOx limits lower than 0.07 lb/MMBtu, such as BMC Thomas Oil facility, Cogeneration National Corporation facility and Corn Products facility. A top-down BACT analysis must assume that the proposed Wolverine CFB boilers can achieve this same level of control.

In addition, limits representing LAER are presumptively appropriate BACT limits. Specifically, NOx LAER limits in other states show that 0.033 lb/MMBtu (24-hr average) is an achievable limit. Unless the LAER level of control can be rejected as not technically feasible, not cost effective, or due to unusual collateral impacts at the permitted site, LAER must be established as BACT. LAER for NOx control from the proposed CFB boilers is at least as low as 0.033 lb/MMBtu over a 24-hour averaging period, which is required by the Dallas-Forth Worth State Implementation Plan for coal-fired boilers.

Moreover, BACT analyses cannot be restricted to existing limits. Instead, BACT must represent the best achievable control, which includes the control achieved by unit operating well below their respective limits. A number of coal fired CFB boilers are achieving lower NOx emission rates than the 0.07 lb/MMBtu limit proposed in the Draft Permit, even with periods of startup and shutdown included (from data taken in 2003). Because these similar units already achieve a lower NOx emission rate—0.043 lb/MMBtu and lower—BACT is assumed to be at least as low as 0.043 lb/MMBtu.

Wolverine rejected the use of SCR achieving 75% control in the "tailend" configuration based on an estimated cost effectiveness of \$20,100 per ton reduced. The cost recently estimated by the Wisconsin Department of Natural Resources when determining the cost effectiveness of a tail-end SCR on a 300 MW coal, petroleum coke and biomass fired boiler that is essentially the identical boiler to the two proposed for Wolverine was \$10,647. In addition to Wolverine and MDEQ's failure to justify the extraordinarily high cost estimates for an SCR, MDEQ also prejudiced the cost-effectiveness analysis.

Response:

In the permits cited by MDEQ, the EKPC Spurlock Unit 3 and 4, does require the limit to be met under all load conditions, however, the permit also has an optimizational period, which if they can not meet 0.07 lb/MMBtu within the 18 month period, they can adjust the limit upward as much as 0.10 lb/MMBtu. However, the second permit cited by MDEQ, Southern Montana Highwood Station permit has the following emission limits for NOx:

Except during periods of start-up and shutdown, NOx emissions from the CFB boiler stack shall not exceed the following:

- a. 0.10 lb/MMBtu based on a 1-hour average
- b. 0.09 lb/MMBtu based on a 24-hour average and
- c. 0.07 lb/MMBtu based on a rolling 30-day average

Since the intermediate loads have been removed from the Wolverine permit (see "Section II. Summary of Comments Resulting In Changes to the Permit", of this document) Wolverine will be required to meet the NOx emission limit of 0.07 lb/MMBtu, based on a 30 day rolling average, at all loads. This limit is the same or lower than the plants listed above.

In the June 2009 additional information submittal, the applicant provides CEMs data measured from 3 similar operating power plants. This information supports 0.07 lb/MMBtu with a SNCR for NOx control as BACT for the proposed Wolverine boilers. The data was obtained from AES Warrior Run Unit 1 (bituminous coal-fired unit), Schiller Unit 3 (wood-fired unit), and JEA Northside Units 1A and 2A (petcoke-fired units).

Wolverine is not subject to LAER. As stated above, the record supports 0.07 lb/MMBtu with a SNCR for NOx control as BACT.

The Commenter also lists several power plants, including some of those that Wolverine provided information on, that the commenter states are achieving lower NOx emission rates than 0.07 lb/MMBtu. Although this may be true at one instantaneous point in time, the data shown in the comment is for the lowest emission rate achieved one time; it does not consider the standard deviation of the data. The standard deviation would demonstrate that those power plants are not continuously achieving the lowest rate possible all the time.

Lastly, the commenter refers to the cost recently estimated by the Wisconsin Department of Natural Resources for the Nelson Dewey plant expansion which was for one 300 MW CFB boiler. The cost of 20,100 per ton reduced estimated by Wolverine was for two 300 MW CFB boilers. Therefore, the cost for each boiler controlled by a tail-end SCR would be \$10,050 per ton reduced, which is less than that cost rejected by Wisconsin.

7. SO2

Comment:

MDEQ does not propose limits reflecting the maximum degree of reduction as shown by permits issued to and/or the performance of other facilities. As noted by Wolverine and the MDEQ itself, the AES Puerto Rico facility in Guayama, Puerto Rico, received a PSD permit for two coal-fired CFB boilers (~225 MW/each) that contains the following SO2 BACT limits applicable to each CFB boiler:

- 9 ppmdv @ 9% oxygen;
- 0.022 lb/MMBtu; or
- 54.1 lb/hour, whichever is more stringent on a three hour basis.

These limits are lower than the proposed BACT limit for Wolverine. Furthermore, this facility was tested in October 2002. Unit 1 achieved 0.00037 lb/MMBtu SO2 emissions. Unit 2 achieved 0.0013 lb/MMBtu SO2 emission.

Similarly, the NEVCO-Sevier facility received a PSD permit for a 270 MW coal-fired CFB boiler with a BACT limit for SO₂ of 0.05 lb/MMBtu over 24 hours and 0.022 lb/MMBtu on a 30 day rolling average. These limits include periods of startup, shutdown and malfunction.

Other coal-fired CFB boiler facilities in California have also received BACT limits much lower than 0.05 lb/MMBtu for SO₂:

- Pyropower Corp. received a SO₂ limit of 0.039 lb/MMBtu for a 49.9 MW coal fired CFB boiler in 1986
- BMCP (Thomas Oil) received an SO₂ limit of 0.039 lb/MMBtu (96% control) for a coal fired CFB boiler in 1986
- Cogeneration National Corp. received an SO₂ limit of 95% control for two coal fired CFB boilers in 1985

However, MDEQ fails to mention these permits at all, let alone explain why they can be rejected as a basis for BACT at the Proposed Coal Plant. Nothing in the permit record suggests any reason why the WCEV cannot achieve at least 0.022 lb SO₂/MMBtu on a 24 hour average, which is the limit for AES Puerto Rico. In fact, nothing indicates why the WCEV cannot achieve 0.0013 lb SO₂/MMBtu, which AES Puerto Rico achieved in practice. Therefore, BACT for SO₂ emissions from the Proposed Coal Plant is 0.0013 lb/MMBtu, or lower.

Additionally, the JEA Northside facility in Florida conducted an emission test in summer 2002, while firing high sulfur coal in its 300 MW CFB boilers, and achieved 0.0-0.04 lb/MMBtu SO₂ emissions. Northside uses a spray dry absorber (dry FGD), similar to the proposal at WCEV. The design specifications required 85% removal of SO₂ in the CFB boiler, and another 89.5% SO₂ removal in the dry FGD. While this is not as low as the AES Puerto Rico emission rates, it is significantly lower than the limits proposed for the WCEV. This further demonstrates that the proposed permits are too high to constitute BACT.

Response:

There were many facilities with CFB coal-fired boilers reviewed. However, during the BACT review, facilities that best represented Wolverine were used to establish BACT. The criteria used was similarity in the unit characteristics, primary and secondary fuels, permit limit, type of pollution control equipment and the level of emissions emitted from the operating plant. The commenter listed several facilities that Wolverine did not mention: Pyropower Corp, BMCP, and Cogeneration National Corp. Those CFB boilers were less than 50 MW which is not a comparable size unit. Also mentioned by the commenter was the Nevco Sevier Power Company which is comparable in size. However, this plant was proposed with the use of low sulfur coal and did not have any stack test data results. The last facility mentioned was the AES Puerto Rico facility which uses coal and petcoke with a maximum of 1% sulfur content. Stack test results provided by the commenter, demonstrated lowest emission rate achieved one time; it does not consider the standard deviation of the data and should not be used to set the BACT emission limit. AES Puerto Rico CEMS data demonstrated an exceedence of the 0.022 lb/MMBtu BACT limit.

MDEQ agrees with Wolverine that the best representative facilities are JEA Northside, Florida and Reliant Energy Seward Power Plant, Pennsylvania. These facilities are similar in all characteristics to the proposed Wolverine facility. Additionally, the CEMs data collected in 2007 and 2008 was used to demonstrate that 0.06 lb/MMBtu is BACT for the proposed CFB boilers at Wolverine.

***June 22, 2009 submittal:** Wolverine submitted additional information (which AECOM collected and processed) that included two years of hourly CEMs data (2007 & 2008) from the Reliant Energy Seward Plant and JEA Northside for comparison to the WCEV units proposed. Based on that data it was concluded that the Seward Plant achieves about 93% overall SO₂ control and JEA Northside achieves about 97% overall SO₂ control. Compared to WCEV with a proposed SO₂ limit of 0.05 lb/MMBtu the overall control efficiency should be greater than 98%.

The following calculation is provided to demonstrate how the control efficiencies were derived:

Petcoke/PRB Blend = 2.97lb/MMBtu (from application submittal Appendix 2, Table 4.2)

CFB 80%: $2.97 \text{ lb/MMBtu} \times (1-0.80) = 0.5940 \text{ lb/MMBtu}$ (SO₂ coming out of CFB)

Scrubber 91.5%: $0.5960 \text{ lb/MMBtu} \times (1-0.915) = 0.050 \text{ lb/MMBtu}$ (12 month averaging period)

Overall (CFB + scrubber): $2.97 \text{ lb/MMBtu} \times (1-0.98) = 0.0594 \text{ lb/MMBtu}$

Comment:

There should be a percent reduction or separate BACT limits for each type of fuel that Wolverine plans to burn. If not, the facility could use lower sulfur petroleum coke or PRB coal, or other coals with lower sulfur and operate their SO₂ controls at lower control efficiencies than established as BACT.

Response:

The MDEQ ranked by control efficiency the feasible control alternatives for sulfur dioxide emissions pursuant to the Clean Air Act, Part 55 and EPA guidance. Site-specific and process-specific variables such as the sulfur content of the fuel were taken into account. When the concentration of SO₂ in the flue gases entering the polishing dry scrubber is high (from burning fuel with a high sulfur content), the control efficiency of the polishing dry scrubber is higher than when the SO₂ concentration is lower. The SO₂ emission limit is dependent on both the sulfur content of the fuel and the control efficiency of the polishing dry scrubber.

Similarly, the clean fuels and control effectiveness components of a BACT analysis are closely linked. The commenter asserts that BACT requires the use of cleaner fuels for SO₂ (in the form of lower sulfur-content coal), and that BACT (at JEA Northside) requires 85% removal of SO₂ in the CFB boiler, and another 89.5% SO₂ removal in the dry FGD.

For the maximum sulfur content in the fuel proposed, a greater than 98% control efficiency overall (80% from the CFB boiler and 91.5% from the polishing scrubber) is necessary to meet the emission limit 0.05 lb/MMBtu annually. MDEQ agrees that the emission limit may be met through use of a lower sulfur content fuel than the maximum design value, and as a practical matter, the actual fuel used will not always contain the maximum allowable sulfur content. As can be seen in the analysis of the examples cited by the commenter (presented below), a 99% control efficiency is achieved at power plants burning high sulfur content fuel. The same level of control efficiency is not achievable when the concentration of the pollutant in the flue gases entering the scrubber is lower.

Also, BACT for SO₂ is an emission limit, based on control efficiency, which is applicable at all times. The MDEQ correctly determined that the dry polishing scrubber can consistently achieve 98% control efficiency at an inlet concentration of 2.97 lb SO₂/MMBtu and that an

SO₂ emission limit of 0.05 lb/MMBtu annually (0.06 lb/MMBtu 30-day rolling average) is BACT.

Comment:

Rejection of wet flue gas desulfurization (WFGD) was improper due to inappropriate technical and unsupported economic assumptions in the BACT determination. The MDEQ provided the following analysis to justify its refusal to require wet Flue Gas Desulfurization scrubber technology (wet FGD):

“No known WFGD systems have been installed or demonstrated in practice downstream of a CFB boiler. Their percent removal efficiency can range anywhere from 52 to 98% and have high capital and operating costs because of the large consumption of water. This control option is frequently used on pulverized coal boilers, and involves the use of a spray absorber tower to contact the flue gas with water/lime slurry sprayed from the top of the tower. Although this control technology has not been used with a CFB boiler, Wolverine considered it technically feasible and included an economic evaluation for application with the proposed CFB boilers. This evaluation yields a cost of \$11,000 per ton of SO₂ controlled. Wet flue gas desulfurization is not an economically viable control option.”

MDEQ must clarify whether it accepted Wolverine's position that WFGD is technically feasible. Assuming that the above quote means that MDEQ rejected WFGD on economic grounds only, we include comments on technical issues as well, both because these issues impact the cost effectiveness outcome and to correct errors and misconceptions in the record.

Response:

Even though MDEQ could not find a CFB boiler with a WFGD system that has been installed or demonstrated in practice, the MDEQ believed it could be feasible. Therefore, a top-down BACT analysis was performed including WFGD.

Comment:

MDEQ erred in citing 80-90% control from WFGD, as wet FGDs can, by themselves, achieve, and have achieved, equal to or greater than 99% removal of SO₂.

Response:

MDEQ cited 52 to 98% as the removal efficiency for a WFGD. The range includes all scrubbers, wet and dry. This range was taken from the Air Pollution Control Technology Fact Sheet, document EPA-452/F-03-034. Also stated in that document, the highest removal efficiencies are achieved by wet scrubbers, greater than 90%, and dry scrubbers, typically less than 80%. Although, newer technology of dry scrubber designs are capable of 90% or more control efficiencies. Based on data that Wolverine provided on June 22, 2009 for additional BACT information, Seward and JEA Northside units achieved SO₂ control efficiencies of 93% and 97%, respectively, using dry FGD.

Comment:

MDEQ accepted the Applicant's economic feasibility argument, thereby failing to include specific information on the WFGD design or designs being considered and relying on unsupported assertions provided by the Applicant. Nor did MDEQ explain its rejection of

WFGD as economically unjustified based on a cost per ton figure of \$11,000. These errors undermine the economic feasibility analysis.

As an initial matter, there are many different types of WFGD, as opposed to DAQ's misleading description of it as consisting of "...a spray absorber tower..." Costs (both capital and operating), as well as operating efficiencies can differ between the various designs. Since WFGD was correctly deemed to be technically feasible, various designs of WFGD should have been considered with regards to cost before they were rejected. MDEQ also accepted Wolverine's cost analysis of WFGD, which concluded that it would cost \$11,000 per ton of SO₂ controlled. The cost analysis did not contain vendor design and related cost. It relied on numerous assumptions that could not be verified and that do not appear to be supported. Since it did not consider a proper (i.e., 99%) removal efficiency, the cost analysis underestimated the tons of SO₂ removal, thereby providing an erroneously high value of the cost-effectiveness. For example, simply by considering a 99% removal efficiency as opposed to 98%, and keeping all other assumptions the same, the cost effectiveness should have been \$5,500 per ton of SO₂ removed, which is well within the acceptable range for costeffectiveness.

Further, it is not clear why the \$11,000 per ton of cost-effectiveness that was calculated by Wolverine should not be deemed to be cost-effective. It is Wolverine's obligation to show that this cost is not "cost-effective" compared to the cost of controlling SO₂ elsewhere. "The top-down approach places the burden of proof on the applicant to justify why the proposed source is unable to apply the best technology available."

Additionally, MDEQ must state for the record what the cut-off for cost-effectiveness is and why. Without this support, DAQ's rejection is arbitrary and the limit is not BACT. The basis for a BACT determination must always be set forth in the public record.

Response:

MDEQ disagrees with this comment. First, Wolverine did use a control efficiency of 99% in the cost analysis for the WFGD system. Second, two similar sources, Southern Montana Electric Generating (Highwood Station) and Virginia City Hybrid Energy Center both did cost analysis for a WFGD system and the following was determined: Highwood Station cost equaled \$27,365/ton SO₂ controlled which did include the cost of water; and Hybrid Energy Center cost equaled \$8,100/ton SO₂ controlled (did not include cost of water), both were considered too costly. Based on that information MDEQ determined that \$11,000/ton SO₂ controlled was also too costly.

Comment:

Putting aside the improper rejection of WFGD, MDEQ also erred by failing to require submission of any specific information as to the polishing scrubber technology that Wolverine is proposing to use. This omission is improper; indeed, it abdicates the DAQ's core responsibility to specify the "technology that is ...the most economical and cost effective" as the basis of its BACT limit. Different polishing scrubbers can achieve different levels of control. It is not possible to divorce the SO₂ control efficiency from the technology that will provide for SO₂ reduction. Requesting this flexibility simply means that Wolverine wants to achieve a target, predetermined SO₂ emissions level which was not arrived at based on what the best technology can achieve. The omission of information regarding the polishing scrubber technology proves that the top-down BACT analysis process was not properly followed.

Response:

MDEQ disagrees with the commenter. As stated above, MDEQ is aware that different polishing scrubbers can achieve different levels of control. In determining BACT (an emission limit) for SO₂ Wolverine used an aggressive yet achievable control efficiency of 98% overall (CFB boiler and dry polishing scrubber) to calculate the SO₂ controlled emission rate. As compared to Seward and JEA Northside, these units have achieved SO₂ control efficiencies of 93% and 97%, respectively, using a dry polishing scrubber. Therefore, MDEQ believes that the SO₂ emissions level was based on what the best technology can achieve.

The following calculation is provided to demonstrate the control efficiencies used:

Petcoke/PRB Blend = 2.97lb/MMBtu (from application submittal Appendix 2, Tables 4.2)
CFB 80% : $2.97 \text{ lb/MMBtu} (1-0.80) = 0.5940 \text{ lb/MMBtu}$ (SO₂ coming out of CFB)
Scrubber 91.5%: $0.5960 \text{ lb/MMBtu} (1-0.915) = 0.050 \text{ lb/MMBtu}$ (12 month averaging period)
Overall (CFB + scrubber): $2.97 \text{ lb/MMBtu} (1-0.98) = 0.0594 \text{ lb/MMBtu}$

Comment:

In addition to the improper rejection of wet FGD, Wolverine did not properly analyze other technologies for SO₂ removal. For example, 90% removal across the a dry scrubber was evaluated as BACT in the South Heart Power Plant permit application, with an inlet SO₂ concentration to the spray dry absorber of 0.392 lb/MMBtu. In the Gascoyne 175 MW permit application, the applicant assumed that the spray dry absorber would remove 89.1% of the SO₂ emissions with an inlet SO₂ emission rate of 0.348 lb/MMBtu. There is ample indication in PSD permit applications that spray dry absorbers can achieve at least 90% SO₂ removal even with low sulfur coals. Indeed, as found by EPA in its review of the New Source Performance Standards for coal-fired electric utility boilers, a spray dryer/absorber can generally achieve greater than 90% SO₂ removal. Wolverine should, at a minimum, accordingly, evaluate an SO₂ BACT limit that reflects at least 90% SO₂ removal across the spray dry absorber. Coupled with a 90% removal in the boiler, for an inlet SO₂ level of 3.0 lb/MMBtu, the outlet emission limit would be 0.03 lb/MMBtu. This limit would be lower still at lower inlet SO₂ levels. Wolverine also failed to evaluate the maximum degree of SO₂ reduction achievable with other technologies, such as circulating dry scrubbers. For example, the Mustang Power Company plans to use a circulating dry scrubber at its proposed New Mexico power plant, and it has indicated SO₂ removal of 97% can be achieved. The applicant must evaluate the maximum degree of SO₂ emission reduction that can be achieved across a circulating dry scrubber in its SO₂ BACT analysis.

Response:

Wolverine did evaluate the emission based on the maximum degree of SO₂ reduction achievable from the inherent scrubbing of the CFB boiler furnace and the dry polishing scrubber. Again, as stated above, the following calculations are provided to demonstrate how the emission limits were derived:

Petcoke/PRB Blend = 2.97lb/MMBtu (from application submittal Appendix 2, Tables 4.2)
CFB 80%: $2.97 \text{ lb/MMBtu} (1-0.80) = 0.5940 \text{ lb/MMBtu}$ (SO₂ coming out of CFB)
Scrubber 91.5%: $0.5960 \text{ lb/MMBtu} (1-0.915) = 0.050 \text{ lb/MMBtu}$ (12 month averaging period)
Overall (CFB + scrubber): $2.97 \text{ lb/MMBtu} (1-0.98) = 0.06 \text{ lb/MMBtu}$

8. CO/VOC

Comment:

The permit fails to include the requirement for good combustion control as part of BACT for CO and VOC while concluding that good combustion control is BACT. Good combustion control is the BACT limit that Wolverine suggests for CO and VOC, and the method that MDEQ acknowledges for CO (although never includes in the permit). The permit ultimately does not incorporate or require good combustion control as a permit operating or other requirement. Identifying good combustion control as BACT, and then not including, it violates BACT requirements.

Response:

The permit does require good combustion control, and it is incorporated in the emission limits for CO and VOC. CO and VOC are formed as a result of incomplete combustion of a hydrocarbon fuel. The permit requires that Wolverine demonstrate good combustion control through continuous monitoring of CO emissions. Continuous monitoring of CO emissions is used to, among other things, reduce the air to fuel ratio to ensure the maximum combustion of fuel, which in turn ensures compliance with the CO and VOC emission limits.

Comment:

The Draft Permit does not contain a BACT limit for VOC. The VOC BACT limit of 0.003 lb/MMBtu is higher than BACT limits for VOC at other similar sources. Provide justification why a limit of 0.0024 (both Santee Cooper, South Carolina and Louisville Gas & Electric Trimble County, Kentucky power plants) cannot be achieved, including an analysis of the energy, environmental, and economic impacts of available control technologies.

Response:

The proposed limit of 0.003 lb/MMBtu could have been explained better. VOC emissions from combustion sources are related to the organic content of the fuels combusted and good combustion practices. VOC emissions are not controlled by an add-on control device and can fluctuate widely, therefore making it difficult to assess an emission limit. Typically, the organic content of subbituminous coal is higher than bituminous coal, and petroleum coke has a lower organic content than coal. The highest organic content fuel that Wolverine is proposing to combust is the biomass. Data is limited for VOC emissions from all of the fuels that Wolverine is proposing to combust. Decisions on the VOC emission limit for Wolverine were mainly based on the performance of JEA Northside which combusts bituminous coal and petroleum coke, two of the lower organic content fuels. The two CFB boilers at JEA Northside had measured VOC emissions of approximately 0.0014 lb/MMBtu when combusting a blend of 90% petroleum coke/10 % coal. This emission rate was higher than the VOC emission rate of 0.00025 lb/MMBtu measured when combusting a blend of 70% petroleum coke/30 % coal. The blend of 70% petroleum coke/30 % coal should contain a higher organic content, and in theory result in higher VOC emissions. In contrast, when combusting 100% coal, unit #1 had VOC emissions of 0.0023 lb/MMBtu measured at 104% of allowed process rate and unit #2 had VOC emissions of 0.000016 lb/MMBtu measured at 92% of allowed process rate. Since VOC emissions were unpredictable and based on lower organic content fuels, a conservative 0.003 lb/MMBtu was assessed for the VOC emission limit which represents a 30% factor of safety over JEA Northside's highest VOC test while combusting coal.

The limit of 0.0024 lb/MMBtu (both Santee Cooper, South Carolina and Louisville Gas & Electric Trimble County, Kentucky power plants) can be achieved when combusting bituminous coal. Santee Cooper Cross, South Carolina combusts similar fuels to JEA Northside. Santee Cooper Cross has demonstrated compliance with the VOC limit of 0.0024 lb/MMBtu, but the MDEQ had more extensive emission data for JEA Northside from 2002 to 2008. The performance of JEA Northside indicates that the VOC emission limit of 0.003 lb/MMBtu is conservative without being too generous. Louisville Gas & Electric, Trimble County has not been built yet so no further evaluation was completed on this unit.

A complete analysis of the energy, environmental, and economic impacts of available VOC control technologies did not have to be performed per the top-down BACT process. Wolverine evaluated two options for VOC control: oxidation catalyst and good combustion control. The oxidation catalyst was found to be not technically feasible for a coal-fired boiler. Good combustion control was found to be the most effective control option, and therefore, selected as BACT.

Comment:

The Draft Permit does not contain a BACT limit for CO. The BACT limit of 0.15 lb/MMBtu for CO is higher than BACT limits for CO at other similar sources.

Response:

For other similar boilers, CO emission limits of 0.10 lb/MMBtu, 0.11 lb/MMBtu, and up to 0.15 lb/MMBtu were reviewed. CO emissions from boilers are a function of oxygen availability (excess air), flame temperature, residence time, combustion zone design, and turbulence. CO emissions like VOC emissions are controlled by good combustion and can fluctuate widely, therefore making it difficult to assess an emission limit. The CO emission limit of 0.15 lb/MMBtu is conservative without being too generous.

Comment:

For CO, the commenter reviewed a large number of permits and stack tests to determine the lowest carbon monoxide emission rate that has been achieved in practice at a similar source. A quick review indicates that the CFB boilers located at the Cedar Bay facility in Florida routinely achieve a lower carbon monoxide emission rate than proposed. Fifteen stack tests conducted between 2003 and 2008 demonstrate that Cedar Bay achieved a carbon monoxide emission rate of 0.05 lb/MMBtu based on a 3-hour average. Similarly low CO levels have been achieved at other circulating fluidized bed boilers. These include JEA Northside circulating fluidized bed boiler, where detailed performance tests were conducted for a range of fuels and at loads of from 40% to 100%. The CO limit is no greater than 0.05 lb/MMBtu based on a 3-hour average, the highest reported CO value over the period 2003 to 2008. This is one-third of the value (0.15 lb/MMBtu) proposed by MDEQ as the BACT for CO, notwithstanding the leniency afforded by MDEQ's longer averaging time (i.e., 30 days).

Response:

The monitoring method for the CFB boilers is a CO CEMS. The monitoring method allows averaging over a longer period of time for a potentially lower CO emission limit. The stack testing results listed by the commenter demonstrate performance for short time frames during stable operation. CO emissions can fluctuate during load shifts and fuel switching, and since the monitoring will measure continuous operation, the emission limit of 0.15

lb/MMBtu was assessed to include a factor of safety. Continuous compliance with a CO limit no greater than 0.05 lb/MMBtu has not been demonstrated as achievable. Likewise, a 3-hour averaging period for CO emissions is not necessary and potentially too restrictive.

Comment:

Several proposed emission limits require compliance on a 30-day rolling average basis. Several similar permits used for comparison in the permit application contain a 3-hour average or 24-hour rolling average. Explain why a shorter compliance time is not feasible for this source.

Response:

A shorter compliance time is feasible for this source. However, the monitoring method selected for the CFB boilers is a CO CEMS. The monitoring method allows averaging over a longer period of time, and therefore, the selection of a lower CO emission limit. The longer averaging time allows for averaging of lower emissions with higher emissions over more emission data. Better performance (good combustion) can be maximized, and fluctuations in CO emissions minimized. A lower CO emission limit means lower CO emissions over the lifetime of the CFB boilers.

Comment:

It has been determined that state-of-the-art combustion techniques and proper and efficient combustion practices represent BACT for toxic air contaminants. Explain in full what this means.

Response:

Best Available Control Technology for Toxics (T-BACT) refers to any chemical or compound emitted to the air other than criteria pollutants (CO, VOC, NO_x, PM, PM₁₀, PM_{2.5}, Sox, and lead). Toxic air pollution in Michigan is controlled under two sets of regulation: (1) state administrative rules and (2) the federal Clean Air Act, as amended. According to Michigan's Rules all known substances can be regulated as toxic air contaminants (TAC), except some substances which have been specifically excluded because they are regulated elsewhere or are considered relatively non-toxic. MDEQ reviewed the amount of TAC emissions the facility could possibly emit after the best controls are installed. Wolverine is required to limit TAC emissions to amounts at or below screening levels which protect the public health. State-of-the-art combustion techniques; such as oxygen availability (excess air), flame temperature, residence time, combustion zone design, and turbulence; aid in complete combustion in the CFB boilers which minimize TAC emissions. State-of-the-art combustion techniques have been considered T-BACT to minimize TAC emissions on many similar projects.

9. Greenhouse Gases (GHG)

Comment:

Circulating Fluidized Bed (CFB) boilers have a significantly greater greenhouse gas impact than Pulverized Coal (PC) boilers, even when burning biomass. Perhaps most egregiously, not only do CFB boilers emit more NO_x and other criteria pollutants than controlled PC boilers and (Integrated Gasification Combined Cycle) IGCC plants, but CFB boilers pose a very serious additional environmental and health concern: CFB boilers emit more

greenhouse gases than PC boilers on a carbon-equivalent basis. While CFB boilers emit less CO₂ than PC boilers, they emit more nitrous oxide than PC boilers. N₂O is a potent greenhouse gas, with almost 300 times the greenhouse gas impact of CO₂. Thus, comparatively, supposedly “clean” CFB boilers emit approximately 15% more global warming pollutants than PC boilers.

Petroleum coke, a fuel burned in CFB boilers, also increases the amount of greenhouse gases from combustion.

Response:

On a lb/MW-hr basis, greenhouse gas emissions from both CFB and PC boilers are very similar. As reported in the (Electric Generating Alternative Analysis) EGAA, NO_x emissions and CO₂ emissions from a subcritical CFB boiler are superior to subcritical PC boiler technology. Supercritical PC boilers are estimated to emit about 30% less NO_x than the proposed CFB boilers. This amount is approximately 0.02 lb/MW-hr. However, even if the proposed facility were to operate at full capacity for an entire year, and all of the NO_x generated from operating at full capacity were assumed to be N₂O, the total greenhouse gas contribution from the additional NO_x emissions is only about 0.3% of the total allowable annual CO₂e emissions.²¹

In addition, emissions of other pollutants, such as hydrochloric acid, lead, hydrofluoric acid, and mercury, are higher for PC boiler versus CFB boiler technology. MDEQ has discretion to consider the priority of the varying pollutants emitted from a facility taking into consideration other State initiatives. Michigan has a statewide mercury reduction initiative, and toxics and health-based rules that limit emissions of these pollutants. Whenever a health-based standard exists, it will almost always be rated a higher priority than a non-health based standard. In the proposed Wolverine CFB boiler project, the emissions of these pollutants are considered a higher priority than greenhouse gases currently are. Thus, MDEQ disagrees with the commenter that PC boiler technology is preferable to CFB boiler technology.

It is a common misconception that CFB boilers emit 15-20% more N₂O than PC boiler technology. This is because early sampling methods yielded incorrect results due to errors inherent in the sampling methods in use. “In the turn of the 1990s nitrous oxide (N₂O) was measured usually by non-continuous methods, such as bag sampling followed by an analysis with gas chromatography (GC). This method, however, was prone to errors. It was noticed that too high N₂O concentrations were determined in bag samples because NO, SO₂ and H₂O formed N₂O as an artifact. Therefore, based on these measurements, wrong conclusions were drawn about nitrous oxide emissions.”²²

It was later determined that, “CFB boilers inherently operate at lower temperatures and have lower NO_x emissions than pulverized coal boilers, but can emit some N₂O. Cell burners (manufactured in 1950s and 1960s) rapidly mix pulverized coal and combustion air resulting in highly turbulent and efficient combustion, but NO_x emissions are high, typically 1.0 to 1.8 lb/mmBTU.”²³ Uncontrolled emissions of NO_x are lower for a CFB boiler than a PC boiler because the combustion temperature of a CFB boiler (1544 - 1652°F) is much lower than a

²¹ $\{(0.02 \text{ \#/Mw-hr}) \times (8760 \text{ hrs/yr}) / (2000 \text{ \#/ton}) \times 310\} / 6,024,107 \text{ tons CO}_2\text{e allowed/yr} \} * 100\% = 0.3\%$

²² Non-CO₂ greenhouse gas emissions from boilers and industrial processes, pgs 26-27, Tsupari, E, et al, VTT Research Notes 2321, ESPOO 2005

²³ NO_x Emissions Produced with Combustion of Powder River Basin Coal in a Utility Boiler, pg 19, WRI-97-R033, Nordin, John S and Merriam, Norman W., April 1997, US Department of Energy Office of Fossil Energy

PC boiler (2462 - 2732°F) which results in lower NOx formation. (NOx present in flue gas generally comes from two sources: the oxidation of nitrogen compounds in the fuel (fuel NOx) and the reaction between the nitrogen and oxygen in the combustion air (thermal NOx). With low temperature and staged combustion, the oxidation of fuel nitrogen is suppressed resulting in very low NOx emissions). Additional control of NOx in the proposed Wolverine CFB boilers are provided by selective non-catalytic reduction (SNCR), which can control NOx with efficiencies up to 75%. For a PC boiler, add-on control of NOx can be provided by selective catalytic reduction (SCR) systems. SCR is a post combustion system that can reduce NOx emissions at 85 to 90% efficiency. However, the higher efficiency of SCR control on a PC boiler does not mean that overall emissions of N2O will be significantly lower than for CFB boiler. Thus MDEQ disagrees that CFB boilers emit 15% more greenhouse gases than PC boiler technology.

Petroleum coke (petcoke) is proposed as one of the fuels in the feedstock mix. On a pounds per ton basis, petcoke does create more greenhouse gases than other fuels. However, it also has a higher heating value, so less needs to be combusted to generate the same amount of energy as other fuels. For example, to get the same amount of energy you get from combusting one pound of petroleum coke, you would need to combust almost 1.5 pounds of sub-bituminous coal and about 1.6 pounds of dry wood (green wood would be considerably higher). The tables below provide information regarding the emissions of individual greenhouse gases in a variety of units, and a comparison of greenhouse gas emissions from the different fuels proposed in the project, based on heating value of the fuel. It is clear from this data that CO2 is by far the largest greenhouse gas emitted from combustion of any of the fuels proposed by Wolverine, even when Global Warming Potentials are applied to the individual greenhouse gases.

GHG emissions in #/mmBTU – proposed Wolverine project

Fuel Type	CO2 (#/mmBTU)	CH4 (#/mmBTU)	N2O (#/mmBTU)
Subbituminous coal	213 (97.02 kg)	0.024 (0.011 kg)	0.004 (0.0016 kg)
Coke	225 (102.04)	0.024 (0.011)	0.004 (0.0016)
Wood/Wood Residuals	206.4 (93.8)	0.07 (0.032)	0.009 (0.0042)

GHG emissions in #/ton fuel – proposed Wolverine project

Fuel Type	CO2 (#/ton fuel)	CH4 (#/ton fuel)	N2O (#/ton fuel)
Subbituminous coal	3682 (1674 kg)	0.042 (0.019 kg)	0.061 (0.028 kg)
Coke	5567 (2531)	0.60 (0.27)	0.087 (0.040)
Wood/Wood Residuals	3174 (1443)	1.08 (0.49)	0.14 (0.065)

GHG emissions from combustion by % (based on #/ton) – proposed Wolverine project

Fuel Type	CO2	CH4	N2O
Subbituminous coal	99.98	0.001	0.016
Coke	99.99	0.01	0.002
Wood/Wood Residuals	99.96	0.03	0.004

GHG emissions from combustion by % (based on #/ton), with GWP's applied – proposed Wolverine project

Fuel Type	CO2 (#/mmBTU)	CH4 (#/mmBTU)	N2O (#/mmBTU)
Subbituminous coal	99.5	0.024	0.49

Coke	99.3	0.22	0.48
Wood/Wood Residuals	97.96	0.70	1.34

GHG emissions from combustion by % (based on #/ton) - EPA data

Fuel Type	CO2 (#/ton fuel)	HHV (mmBTU/ton)	Fuel Needed to equal HHV value of coke	Total CO2 emissions to equal HHV of coke
Coke	5579	24.8	1	5579
Subbituminous coal	3689	17.25	1.44	5304
Ag Biomass	2149	8.25	3	6447
Wood/Wood Residuals (dry)	3180	15.38	1.61	5128

Thus, MDEQ disagrees with the commenter that PC boiler technology is preferable to CFB boiler technology.

Comment:

The “redefining the source” rationale does not apply in the present case. Wolverine eliminated multiple available technologies, including natural gas combined cycle, pulverized coal, super critical CFB boilers, Integrated Coal Gasification Combined Cycle, and biomass gasification, as control options by stating “they would constitute ‘redesign’ or ‘reconfiguration’ of the project.” GHG Permit Appl. at 1-2. The “redefining the source” rationale does not apply to options that would reduce pollution while redesigning or reconfiguring the project. Rather, it permits the agency to exercise limited discretion to omit options that would fundamentally “redefine the source”. MDEQ applies redefining the source too broadly.

Response:

MDEQ disagrees with the commenter. The “redefining the source” question is been discussed in the NSR Workshop Manual (*page B.13*) and evaluated by the courts in a number of documents. These documents indicate that an applicant is not required to evaluate cleaner fuels in the BACT analysis, but should evaluate cleaner forms the selected fuel source for the project. Other court decisions have clarified that an applicant is not required to evaluate fuels that would fundamentally change the scope of the project.²⁴ In other court decisions, it was determined that the question of redesign of a facility to achieve reduced emissions is the kind of judgment which should be left to the Permitting Agency.²⁵ MDEQ, as the permitting authority, has appropriately applied its discretion in applying the redefining the source rationale.

Comment:

Site specific criteria are not a valid reason for excluding control options. As MDEQ points out, elimination of control technologies must be for reasons such as “not technically or economically feasible or that energy, environmental, or economic impacts are unfavorable.” If MDEQ were trying to invoke the collateral impacts exception here, it failed to do so. An alternative clean fuel may only be rejected for the single additional reason of when “using

²⁴ Old Dominion, 3 E.A.D. 779 (1992)

²⁵ Sierra Club v. EPA, 499 F.3d 653, 655-6, on appeal of the EAB’s Prairie State decision, and Hawaiian Commercial & Sugar Company, 4 E.A.D. 95 (1992)

another type of fuel would be inconsistent with the fundamental purpose of the facility.” Consequently, since consideration of clean fuels is required as part of the BACT analysis, the applicant and MDEQ were required to consider natural gas.

Response:

Site specific criteria were not used to exclude control options. However, site specific criteria did make the selected control options and boiler design more attractive than other controls and designs considered in the BACT analysis. For example, by locating the CFB boilers in this specific limestone quarry, a ready source of limestone is available for SO_x control, pre-softened water is available for cooling, an on-site ash disposal site is available, and a dock is available for delivery of fuel.

The consideration of clean fuels in the BACT analysis only requires consideration of cleaner forms of the fuel being proposed. This is clearly explained in the October 1990 draft *NSR Workshop Manual*. Since Wolverine has designed a plant that will burn petcoke, Powder River Basin coal, and biomass, MDEQ may consider cleaner forms of these fuels. Consideration of natural gas is beyond the scope of the BACT requirements. However, it was considered as part of the alternatives analysis.

Comment:

Wolverine also rejected the use of 100% biomass combustion, stating that a 100% biomass CFB boiler is limited to 50 MW in size which does not meet the needs of the project. The use of 100% biomass as fuel in a fluidized bed combustor greater than 50 MW, however, has been demonstrated as technologically feasible and was therefore unreasonably rejected as a control option for the WCEV project. Since May of 2010, a Foster Wheeler 385 MW circulating fluidized-bed combustor has been operating for Kaukaan Voima Oy in Finland firing 100% biomass. The power plant is fueled by bark, branches, tops, stumps, small wood and peat.

Response:

MDEQ disagrees that the Kaukaan Voima Oy CFB boiler has the ability to provide similar electrical output to the proposed Wolverine CFB boiler using only biomass. The Kaukaan Voima Oy CFB boiler plant can provide 125 MW of electricity, 110 MW (thermal basis) of district heat, and 150 MW (thermal basis) of process steam. The actual electrical output is only 125MW, which is approximately 35% of the capacity of the CFB boilers proposed by Wolverine, which can provide 350 MW (each) of electricity.

Comment:

Wolverine also did not evaluate the use of torrefaction to prepare the biomass to reduce the cost of transportation and fuel handling.

Response:

Torrefaction is the process of heating the raw biomass to drive off water and volatiles. The remaining material is a charcoal or bio-coal, and can be used in the combustion process along with coal and other fuels. The advantage of torrefaction is that the final product has about 30% more energy per unit of mass, and transportation costs per unit of energy decrease. However, about 10% of the original energy in the biomass is lost due to the volatile materials being driven off in the torgas.

Torrefaction was not reviewed during the GHG BACT review. However, it should be noted that torrefaction does not come without its own production costs and environmental penalty. Fuel must be burned to create the heat needed for the torrefaction process. The biomass would have emissions of greenhouse gases along with other pollutants such as volatile organic compounds. So, even though there may be savings from lower transportation costs or better fuel handling characteristics, the burning of a bio-coal is not necessarily a cleaner form of biomass, and the same or higher amount of greenhouse gases may be emitted through the course of the process.

MDEQ does not believe that consideration of torrefaction would have changed the outcome of the GHG BACT analysis.

Comment:

While both the applicant and MDEQ have relied upon site-specific criteria as if they define the source, these site specific criteria do not rise to the level of being a fundamental purpose of the project. The purpose of this project, generating electricity, would still be achieved if the project location, combustion technology and fuels were changed to generate significant reductions in GHG emissions.

Response:

MDEQ disagrees that the ability to take advantage of site-specific attributes were a fundamental purpose of the project. While it is true that site-specific criteria do not define the fundamental purpose of the project, the selection of the appropriate combustion process does impact the analysis and outcome of the decision. Site-specific attributes are one of the many considerations that may have an affect on the selection of the process employed and the control strategy. For example, site-specific attributes may make one control strategy more cost effective or a combustion process alternative more feasible. The site specific factors were just one element that influenced Wolverine's selection and MDEQ support of a CFB boiler.

Comment:

Although scientists have now thoroughly debunked the long-standing myth that biomass combustion is "carbon neutral," industry proponents and project applicants continue to seek special treatment for biomass projects based on the dangerously false contention that biogenic greenhouse gas emissions do not affect the climate. The company and the State simply assume, but never actually demonstrate, that biomass combustion should be considered carbon neutral.

The GHG BACT Determination "considers" biomass combustion to be "carbon neutral." The weight of current scientific work compels the opposite conclusion.

The GHG BACT Determination claims that "the implementation of a sustainability standard"—specifically one derived from Michigan law defining "sustainably managed forests"—is "the key to documenting the carbon neutrality" of fuels. Yet the document fails to demonstrate that any of the referenced sustainable forestry certification methods even considers the atmospheric impact of biomass combustion, much less establishes "carbon neutrality." This assumption, however, relies on a simplistic, inventory-based accounting approach that ignores both real carbon dynamics and the legal requirements of the Clean Air Act.

Response:

In March 2011 EPA published the *Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions From Bioenergy Production*. This document provides a general discussion regarding biomass as an overall net carbon sink, and discusses how CO₂ emissions participate in a global carbon cycle through photosynthesis, which is a form of terrestrial sequestration. In this document, EPA states that averaged over the years 1990-2008, the United States has been a net sink of 841 teragrams of CO₂e per year (about 12% of the average gross emissions). EPA further states that this net carbon sink is expected to continue, if not increase, through 2020.²⁶ While combustion of biomass may or may not be carbon neutral, MDEQ follows EPA guidance and treats CO₂ emissions from biomass as a net carbon sink, and therefore preferable to combustion of fossil fuels.

Comment:

Since the March 16, 2011 GHG BACT determination has been prepared and submitted well after the application, it can be concluded that many of the project design considerations including project location, combustion technology and fuels were chosen with no consideration to minimizing GHG emissions. Further, since the project and permit remained virtually unchanged after the GHG BACT analysis, the BACT analysis appears to have come to the predetermined conclusion that the project and permit as written were BACT for GHGs instead of the BACT analysis driving the pollution controls and emissions limits for the project.

Response:

MDEQ strongly disagrees with this comment. Since the original BACT analysis was performed more than a year before the GHG BACT was required, it may seem that the conclusions were predetermined. However, this was not the case.

It is important to remember that the GHG BACT analysis submitted by Wolverine on March 16, 2011, is a supplement to the original BACT analysis for the conventional criteria pollutants. After considering the information in the original application, the original BACT analysis concluded that the CFB boiler as proposed was the best design choice. With the addition of the regulation of GHGs, the question becomes; does the regulation of GHGs change the original conclusion? It is clear that some technologies, such as IGCC, offer an attractive option for capturing CO₂. However, the ability to capture CO₂ becomes a less attractive feature without the ability to sequester it. In their March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases* document, EPA found that while CCS is a promising technology, there are numerous reasons to eliminate it because it is technically infeasible at this time. During our review of the GHG BACT supplement, MDEQ concluded that this was the case for the Wolverine project.

Next, we determined if any of the other technologies offered any advantages that would reduce GHG emissions significantly enough to outweigh the conclusions of the original analysis. Again, MDEQ concluded that the other technologies did not provide overwhelming evidence that would necessitate a redesign of the proposed facility.

²⁶ Guidance for Determining Best Available Control Technology for reducing Carbon Dioxide Emissions from Bioenergy Production, March 2011, USEPA, pg 7

This left evaluation of the existing proposed CFB boiler design with respect to reduction of greenhouse gas emissions. MDEQ determined that energy efficiency, and a requirement for use of a renewable energy in the form of biomass in the fuel mix, was BACT for GHGs.

Thus, while conclusions reached in the original BACT analysis may influence the results of the GHG BACT analysis, the GHG BACT was performed independently.

Comment:

The GHG BACT Determination fails to follow several of the steps recommended by EPA for a top-down BACT analysis and thus fails to ensure that the determination adequately addresses all relevant regulatory and statutory requirements. The document also fails to support conclusions reached at several of these steps with facts or data in the record.

Response:

Guidance from EPA states that, "...EPA has not established the top-down BACT process as a binding requirement through rule. Thus permitting agencies that implement an EPA-approved PSD permitting program contained in their State Implementation Plans (SIPs) may use another process for determining BACT in permits they issue, including BACT for GHGs, so long as that process (and each BACT determination made through that process) complies with the relevant statutory and regulatory requirements."²⁷ Although MDEQ typically follows the top-down process, it is not unusual to combine steps when appropriate. Because the GHG BACT analysis was a supplement to the original BACT analysis submitted by Wolverine, a modified process was used to evaluate the supplemental information. However, all steps required in the top-down review process were included by MDEQ in the modified analysis.

Comment:

IGCC is a technology that can lower control costs of CO₂ emissions because the CO₂ in the syngas can be removed prior to combustion. MDEQ and Wolverine failed to include IGCC in the full BACT analysis eliminated it prior to Step 1. MDEQ did do a cost analysis of IGCC within the earlier BACT analysis for other criteria pollutants. However, the omission of GHGs from the list of reduced pollutants fails both to attribute some of the cost of the plant to control of these harmful pollutants and to spread the cost of controlling other pollutants across GHG reductions. Had IGCC been included in the cost-effectiveness analysis for GHG controls, step 3 of the BACT analysis, the favorable costs for GHG reductions coupled with greater cost effectiveness for other pollutants would have produced a significantly different overall picture of IGCC. MDEQ was arbitrary and capricious in failing to analyze BACT for GHGs with IGCC with CCS as a control option.

Response:

It is clear that some technologies, such as IGCC, offer an attractive option for capturing CO₂. However, the second step is sequestration. The ability to capture CO₂ becomes a less attractive design feature without the ability to sequester it. In their March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases* document, EPA found that while CCS is a promising technology, there are numerous reasons to eliminate it in the BACT analysis because it is technically infeasible at this time. During our review of the GHG BACT supplement, MDEQ concluded that this was the case for the proposed Wolverine project.

²⁷ PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011, USEPA, pg 19

Comment:

Wolverine and MDEQ should have looked beyond Wolverine's DOE project as the basis for its cost estimates for using CCS to control GHGs. As explained elsewhere in these comments, IGCC technology should have been considered for the plant, instead of solely CFB boiler technology.

Response:

In addition to the many technical hurdles to overcome, current information suggests that the cost structure for CCS is very high. However, there is very little information available on the cost structure for CCS, which is why we elected to evaluate the CCS option with the Wolverine-DOE grant proposal information. Based on the information in the proposal, MDEQ found that to sequester even 5-6% of the total exhaust would cost approximately \$128 per ton. Considering the large number of tons of greenhouse gases produced through the combustion process, MDEQ determined that CCS was not cost effective.

Comment:

The BACT analysis submitted by Wolverine and the BACT review conducted by MDEQ are further inadequate because they improperly dismiss CCS as BACT for controlling emissions of CO₂ from the facility. Wolverine and MDEQ err in claiming that CCS is not an "available" technology for BACT purposes. Second, Wolverine and MDEQ make an unsupported and flawed argument that CCS is not economically feasible.

Response:

MDEQ did not claim that CCS was not an available option. MDEQ is well aware that EPA considers CCS an available technology.²⁸ However, EPA also indicates in this document that while CCS is a promising technology, there are numerous reasons to eliminate it as technically infeasible at this time, recognizing that the significant logistical hurdles presented by CCS technology sets it apart from other conventional forms of pollution control equipment. Off-site land acquisition, funding, and liability for long term storage were all cited in the EPA guidance document as making CCS prohibitive at this time. Thus, MDEQ eliminated CCS in Step 3 of the BACT analysis for these reasons.

Comment:

An example of a recent permit for a supercritical plant is that issued for a new unit at the Trimble County Generating Station. AEP Southwestern Electric Power Company recently obtained a permit to build a 600 MW ultra-supercritical unit in Arkansas. In addition, ultra-supercritical units have been permitted and in use overseas. MDEQ shows the randomness of its BACT process: the agency required IGCC to be considered in the BACT analyses for the supercritical PC boiler plant proposed by Consumer's Energy and the subcritical CFB boiler proposed here, but did not require Wolverine to consider SPC in its BACT analysis for the subcritical CFB boiler. MDEQ must explain why IGCC is an alternative to supercritical PC boiler and the Wolverine subcritical CFB boiler for criteria pollutants, but supercritical PC boiler is not an alternative to the proposed plant for GHGs. Ultra-supercritical PC boiler also should be considered in the GHG BACT analysis.

²⁸ PSD and Title V Permitting Guidance for Greenhouse Gases, USEPA, March 2011

Response:

Pulverized coal (PC) boiler technologies (subcritical, supercritical, and ultra-supercritical) were eliminated in Step 2 of the BACT analysis because they do not have the demonstrated ability to utilize the mixture of fuels proposed by Wolverine. Although PC boiler technology is capable of burning biomass, special handling is required when biomass exceeds about 3% of the fuel mix due to physical limitations of the pulverizer. (Wolverine Power Cooperative Electric Generation Alternatives Analysis – Volume 1, Appendix A-2, June 8, 2009, pg 17)

In addition, PC boiler technology would not take advantage of site-specific characteristics to the extent that CFB boiler technology does. CFB boiler allows direct addition of limestone in the boiler feed for sulfur control. PC boiler technology would require wet flue gas desulfurization, and which would create a new wastewater stream that would have to be collected and treated.

Furthermore, greenhouse gas emissions are within about 3% of each other for these technologies while emissions of lead, hydrochloric acid, hydrofluoric acid, and mercury all increase with PC boiler technology.

Therefore, the MDEQ has determined that there is no significant advantage to PC boiler technology that would outweigh the benefits derived by selecting CFB boiler.

Comment:

Given the requirement to conduct BACT for greenhouse gases as well as criteria pollutants, MDEQ should have considered a supercritical CFB boiler in its BACT analysis. MDEQ references the supercritical CFB boiler constructed in 2009 for the Łagisza Power Plant in Poland, but states that “there is limited information on the performance of the unit” and dismisses this as a “developing technology.” In March, 2010, Foster Wheeler concluded that: “After operating over 4000 hours, it can be stated that initial operation experience of the Łagisza boiler has been excellent.” Due to the success of the Łagisza CFB boiler, Foster Wheeler is moving forward to design an 800 MW supercritical steam CFB boiler. The Łagisza supercritical CFB boiler has operated successfully for over 1 and half years. Wolverine concludes both facilities have a similar heat rate but dismisses supercritical CFB boilers as not being demonstrated as capable of operating with biomass fuels. However, Foster Wheeler itself indicates that supercritical CFB boilers can fire up to 20% biomass, the percentage proposed by Wolverine. MDEQ and Wolverine were required to conduct a more thorough BACT analysis of the availability and feasibility of this technology and may not arbitrarily dismiss it as developing because the designs for the Wolverine plant call for a subcritical CFB boiler.

Response:

While supercritical CFB boiler technology shows great promise, after only 6 months of operation we believe it is premature to require supercritical CFB boiler technology as BACT over subcritical technology, which has a very long and successful history. There is been very little information available regarding operation of the Łagisza CFB boiler other than Foster Wheeler’s literature. Based on an information search via the internet, it appears that the Łagisza CFB boiler is still under-going fine tuning and has yet to undergo stack testing to verify vendor guarantees. “After fine tuning of controls and optimization of the boiler

performance, a 720 h trial operation will begin followed by plant takeover and start of the commercial operation.”²⁹

While emission results are available in the Foster Wheeler literature, the background data, testing methods, and verification of data, are not provided in any of the literature we were able to find. At this point it is not even clear if fuels other than European bituminous coals have been used in the boiler and if so, in what ratios.

Nor is it clear if the technology will continue to perform at such high reported efficiencies over time. With the exception of a few news articles reporting on the new technology, almost all of the available information has been provided by the vendor, Foster Wheeler. However, this information does not provide any information that allows an independent party to verify the reported efficiency of the unit.

In addition, since the unit has only been in operation for about a year and a half, maintenance and reliability have yet to be proven. However, the sub-critical CFB boiler technology proposed by Wolverine is well proven with the technology, fuel mix, and air quality control strategies proposed. Wolverine is staking the future of the company on this proposed facility, and cannot be expected to risk the viability of their company with a technology that is still being verified by the vendor.

For these reasons, supercritical CFB boiler is currently considered a developing technology by the MDEQ.

Comment:

The GHG BACT Determination lists “biogenic fuel augmentation” among the “possible control technologies” identified for the Project, but does not explain why this technology is even appropriate for identification at Step 1 of the BACT analysis. The purpose of Step 1 is to identify “inherently lower emitting processes/practices,” add-on controls, and combinations thereof. The GHG BACT analysis does not demonstrate that biomass combustion is “inherently” lower-emitting. Indeed, biomass combustion can result in more greenhouse gas emissions per unit of energy produced than either coal or natural gas.

Response:

MDEQ believes it is appropriate to include biogenic fuel augmentation as an available technology. While it is true that biomass may emit more greenhouse gas on a heat input basis, it is also considered a renewable and “carbon neutral” fuel. Selection of biomass as BACT is supported in of the March 2011 *Guidance For Determining Best Available Control Technology For reducing Carbon Dioxide Emissions From Bioenergy Production*. On page 29 of that document, EPA states “[forest] residuals that would otherwise decompose in a 10-15 year time frame, the net carbon cycle impact of this biomass fuel is expected to be negligible. Thus for a feedstock composed of such residue material, the costs of applying strategies to reduce emissions from the facility do not appear justified at this time because the carbon dioxide emissions from the individual facility would not be increasing atmospheric impacts above the business as usual case.” EPA further states “...EPA believes the energy and economic benefits of this fuel is sufficient at this time to justify selecting biomass fuel as BACT for greenhouse gases without further control.”

²⁹ Utility CFB goes “Supercritical” – Foster Wheeler’s Lagisza 460 MWe Operating Experience and 600-800 MWe Designs, James Utt, Arto Hotta, Stephen Goidich, August 19-21, 2009, pg 11, http://www.fwc.com/publications/tech_papers/files/TP_CFB_09_12.pdf

MDEQ concurs with EPA guidance, and included biogenic fuel augmentation as an available technology in Step 1 of the BACT analysis.

Comment:

The GHG BACT Determination's discussion of the technical feasibility of burning biomass as BACT begins not with any technical analysis, but rather with a survey of federal and state policy provisions that favor biomass energy generation. These policy judgments have no place in a BACT analysis.

Response:

MDEQ disagrees with this comment. Selection of biomass as BACT is supported in of the March 2011 *Guidance For Determining Best Available Control Technology For reducing Carbon Dioxide Emissions From Bioenergy Production*. On page 27 of this document EPA states, "Renewable fuels policies, which in some cases provide incentives for the substitution of renewable fuels for fossil fuels, have not traditionally been part of the BACT energy impacts analysis. However, consideration of renewable energy policies could become part of the BACT analysis, especially if state policies mandate the replacement of fossil fuel with biogenic fuel. In addition to numerous federal programs, as of February 2011, states have some kind of state-level financial or conservation incentive program that includes biomass production and almost as many states have rules, regulations or policies that promote bioenergy use."

EPA further states that "...where a bioenergy facility is projected to provide the energy and economic benefits described above in accordance with existing federal or state policies promoting utilization of biomass for energy production, these considerations may justify selecting the option of exclusively using a biomass fuel as BACT for biogenic CO₂ emissions from a bioenergy facility."

Clearly, the EPA guidance supports permitting agencies factoring federal and state policies into the BACT determination for biomass. MDEQ concurs with this approach and factored this into the evaluation process.

Comment:

The GHG BACT Determination also fails to provide any meaningful discussion of the environmental impacts of co-firing with biomass. The GHG BACT Determination fails to answer even the most basic questions: what is the environmental effect of collecting and burning biomass from areas within 75 miles of the Project? What are the effects at a 5% co-firing rate, as opposed to a 20% co-firing rate? What is the effect (on soils, water quality, and habitat) of removing logging residuals and burning them, rather than leaving them in the forest? The MTU Report provides no actual evidence for concluding that every acre of "herbaceous open land" or other "open lands" is, in fact, "abandoned agricultural land." Nor does the MTU Report provide any support for its conclusion that energy crop conversion will be beneficial for biodiversity.

Response:

The MTU Report estimates that Wolverine would require approximately 168,105 dry tons of biomass per year to provide 5% feedstock, and 672,418 dry tons biomass per year to

provide 20% of the total feedstock.³⁰ MTU also estimates that the "... 'unused' portion of annual removals, comprised of logging residues that are normally left on-site and 'other' removals, such as road and right-of-way clearing and thinning treatments", would provide approximately 220,000 dry tons of biomass, or about 7%, annually, assuming a 65% recovery rate of this material.³¹ As described in the report, this estimate considered only the currently unused portion of biomass residues as material that is available to Wolverine within a 75-mile radius of the proposed facility. In addition, collecting this material will reduce emissions generated by decay of this organic material.

MTU also found that Michigan Forests are currently growing more wood than is removed through timbering and natural mortality. Currently, average harvest levels in Michigan's northern lower peninsula are about 1/3 of current growth. If this additional existing biomass growth were used, co-firing at more than 20% biomass would be feasible in a supply radius of 50-miles.³²

While MTU acknowledges that sufficient information is not available to draw strong conclusions, they were able to use various governmental databases and the knowledge of local county extension and USDA staff to develop recommendations. Available herbaceous open land was estimated using "...data from the USDA Forest Service, Forest Inventory and Analysis Program (FIA)(Miles 2007) and the agricultural and open-land based using data from the State of Michigan's IFMAP (Integrated Forest Monitoring, Assessment and Prescription) program (MI DNR 2006)."³³ Through personal communications with county extension and USDA personnel, MTU learned that much of the land identified as herbaceous open-land is actually abandoned farm land.³⁴

The study looked at both available unused forest residuals and other removals (such as brush clearing), and development of a sustainable biomass feedstock through dedicated energy crops. MTU estimates that there are an additional 980,000 dry tons per year of biomass that could be made available through development of a dedicated energy crop program.³⁵ This is more than sufficient to support a 20% biomass feedstock.

Thus MDEQ has determined that the MTU report findings support the conclusions reached in the GHG BACT review with respect to biomass sustainability and supply.

Comment:

The GHG BACT Determination concludes that co-firing with 5% biomass will reduce CO₂e emissions by 4.7%. GHG BACT Determination at 3-13. Nowhere does the document explain how this figure was calculated. Nor does the MTU Report contain any data to substantiate

³⁰ Biomass Co-Firing for the Wolverine Clean Energy Venture, Michigan Technological University, January 30, 2008, page 2

³¹ Biomass Co-Firing for the Wolverine Clean Energy Venture, Michigan Technological University, January 30, 2008, page 7

³² Biomass Co-Firing for the Wolverine Clean Energy Venture, Michigan Technological University, January 30, 2008, page iii

³³ Biomass Co-Firing for the Wolverine Clean Energy Venture, Michigan Technological University, January 30, 2008, pg 6

³⁴ Biomass Co-Firing for the Wolverine Clean Energy Venture, Michigan Technological University, January 30, 2008, page 6

³⁵ Biomass Co-Firing for the Wolverine Clean Energy Venture, Michigan Technological University, January 30, 2008, page 8

this claim. As a result, the GHG BACT Determination lacks any support for its ultimate conclusion that co-firing with 5% biomass should be considered BACT.

Table 1 of the Supplemental Update seems to include CO₂ emissions from biomass in the Project total of 5,878,168 tpy CO₂e from the CFB boilers. The GHG BACT Determination states that all proposed BACT measures, including biomass co-firing at 5% and energy efficiency measures, will result in a 4.7% reduction in CO₂e emissions. The document proposes to enforce a 5,722,000 tpy “cap” on CO₂ emissions through “continuous emissions monitors at the CFB boiler stack.” The proposed cap would result in a reduction of only 156,168 tpy CO₂e from the CFB boilers. A 4.7% reduction in CO₂e emissions from the CFB boilers, however, should be 276,274 tpy.

Response:

The Wolverine BACT submittal indicates that through co-firing using 5% biomass in the fuel feedstock, implementing energy efficiency measures, and following the manufacturer’s guidance for proper operation of equipment, the net result is a reduction of greenhouse gas emissions attributable to fossil fuels is approximately 4.7%. However, because greenhouse gas emissions reductions attributable to energy efficiency and following manufacturer’s guidance are not easily quantifiable, the actual reductions are expected to be slightly higher than estimated because this figure was calculated using only greenhouse gas emissions from fossil fuels that would be eliminated through the use of biomass.

The Wolverine BACT submittal calculates that at a 5% biomass feedstock rate, 284,000 tons of CO₂e emissions from fossil fuels will be avoided. The report also discusses a 5,722,000 ton per year cap on CO₂e emissions from the boiler.

$$4.7\% = [(284,000 + 5,722,000) / (5,722,000)] * 100\%$$

Note that these values were not used in the AQD review due to a miscalculation of the total CO₂e emissions from the proposed facility in the Wolverine BACT submittal. This error was later corrected, but the reduction in CO₂e emissions from fossil fuels was not recalculated.

Comment:

It is not clear how this “cap” will be enforced. The GHG BACT Determination proposes to measure the cap “with continuous emission monitors at the CFB boiler stack,” which will necessarily capture biomass CO₂ emissions as well.

Response:

The proposed deferral of CO₂ from biogenic sources is not final at this time. Therefore the greenhouse gases from biomass combustion are not exempt from regulation and must be counted when determining compliance with the proposed emission limit. MDEQ has proposed conditions in the permit that account for all greenhouse gas emissions.

Comment:

The Biomass Study fails to account for the greenhouse effects of burning standing timber, which will include N₂O and other compounds which are far more potent greenhouse gases than CO₂. It does not account for the short-term reduction in sequestration caused by increased harvesting and burning of wood with currently sequestered and subsequently released carbon, nor the N₂O emissions from burning wood. The greenhouse effects of

other gases, such as N₂O, which are released by burning wood, are released from CFB boilers, and are many times more potent than CO₂. The analysis must include amounts and multipliers of these more potent greenhouse gases.

Response:

Higher GWP greenhouse gases were included in the analysis. Greenhouse gases with higher Global Warming Potentials (GWP), such as methane (CH₄) and nitrous oxide (N₂O), were evaluated as part of the review process to determine their contribution to the total CO₂e. Using CO₂e allows us to compare greenhouse gases with different GWP, (e.g. 1 ton of N₂O is equivalent to 310 tons of CO₂). Thus one ton of N₂O equals 310 tons of CO₂e. However, even though N₂O has a much higher GWP than CO₂, the total N₂O emissions from the CFB boilers account for less than 0.5% of the total CO₂e emissions (GWP applied). Thus, the effects of higher GWP greenhouse gases such as methane and N₂O were considered by MDEQ in the analysis.

Comment:

Minimizing CO₂ emissions in the next few years is critically important to meeting climate targets, even if some of all of that CO₂ might in theory be reabsorbed from the atmosphere in the decades or centuries to come.

Response:

Existing rules regulating greenhouse gas emissions do not take the effects of climate change into consideration. EPA specifically provides guidance contrary to this effort, "As a general matter, GHG emissions contribute to global warming and other climate changes that result in impacts on the environment and society. However, due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions currently is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying these exact impacts attributable to the specific GHG source obtaining a permit in specific places is not currently possible with climate change modeling. Given these considerations, an assessment of the potential increase or decrease in the overall level of GHG emissions from a source would serve as the more appropriate and credible metric for assessing the relative environmental impact of a given control strategy."³⁶

Comment:

The GHG BACT Determination fails in its most basic task: providing an assessment of the relative cost-effectiveness of burning biomass. Indeed, neither the GHG BACT Determination nor the MTU Report quantify the cost of control for combustion of biomass at 5% of the fuel mix (the proposed BACT measure).

Response:

Step 4 of the BACT analysis is to evaluate the most cost effective control strategies, and Step 5 is to select BACT. No cost analysis was required for the following reasons:

- Selection of biomass co-firing with the primary fuel meets existing state policies promoting utilization of biomass for energy production, thereby reducing carbon emissions from fossil fuels.

³⁶ (PSD and Title V Permitting Guidance for Greenhouse Gases, USEPA, March 2011, pgs 41-42)

- Co-firing 5% biomass with the primary fuel would not significantly reduce the efficiency of the boiler even when using biomass with higher moisture contents.
- The MTU study found that at a recovery rate of 65%, 220,000 dry tons per year of existing forest residuals are available within a 75 mile radius of the proposed facility. This is more than sufficient to meet the 5% biomass requirement in the permit.
- The cost of using biomass is offset by the reduction in costs associated with petcoke and PRB coal.

Based on these factors, MDEQ believes that a minimum of 5% biomass in the fuel feedstock is both technically feasible and cost effective.

Comment:

The discussion of potential energy efficiency measures in the GHG BACT Determination is underdeveloped and fails to follow EPA guidance. Indeed, the discussion does not even identify which specific efficiency measures are being proposed. The document thus provides no basis for determining which energy efficiency measures are available and applicable to this Project.

Response:

The concept behind incorporating energy efficiency measures into the draft permit for the proposed facility is that when the plant is operated as efficiently as possible, the power needed to operate the plant is reduced, thereby reducing overall fuel consumption and emissions of greenhouse gases.

Energy efficiency measures are largely determined during the design of the plant during planning and engineering phases. The general efficiency of the proposed plant is evaluated as part of the BACT process. Specific energy efficiency measures are determined during final design of the plant and during development of operational practices. Because Wolverine is not at the final design stage, it is technically infeasible to identify specific energy efficiency measures that will be employed in the final design because the measures selected will be dependent on facility-specific, as-built site conditions. Therefore, energy efficiency measures can only be identified in the permit in a general sense at this time.

However, MDEQ has included language in the proposed permit that specifies that during the design phase of the project, Wolverine shall incorporate energy efficient equipment wherever practical in the design of each boiler included in FGCFB. Specifically, MDEQ has required that the design of each boiler, at a minimum, shall specify that all motors over 100 horsepower shall be variable speed, all air pollution control devices shall be operated at the minimum pressure drop required to maintain compliance with permit limits and conditions, thermal performance of all heat transfer components at the facility, including structures, shall be designed to maximize energy efficiency, and energy efficiency shall be optimized, where practical, for all fans, motors and other equipment necessary to operate each boiler and support systems.³⁷

MDEQ has also included language in the proposed permit to address energy efficiency through an Energy Efficiency Management Plan (EEMP). This is a living document and is intended to influence not only design and operation of the facility when it is initially constructed, but also to incorporate changes once experience is gained through on-going

³⁷ Wolverine Power Supply Draft Permit to Install No. 317-07, FGCFB, IV.4

operation of the facility. Permit conditions requiring the source to address a concern prior to construction is common practice for other similar situations, such as Malfunction Abatement Plans (MAP) and Fugitive Emission Control Plans (FECP), and provides the State with continued oversight of the project for specific purposes even after permit issuance.

In their March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases* (pg 21), EPA also recommends performance benchmarking as a method to assess energy efficiency.³⁸ Plant energy benchmarking is the process of comparing the energy performance of one site against itself over time or against the range of performance of the industry, and is typically done at the whole facility level to account for differences in technology, operating practices, and operating conditions.³⁹ Since the Wolverine CFB boilers have not yet been constructed or operated, performance benchmarking is of limited use at this time.

EPA also recommends the use of output based limits when numerous small energy savings methods are employed in the design and operation of a facility.⁴⁰ MDEQ has included an output based limit of 2.1 lb/KW-hr on a gross output basis. This limit is intended to not only include energy efficient design and work practices in the proposed plant, but also to require them to maintain a high level of energy efficiency throughout the life of the facility.

Comment:

The GHG BACT Determination fails to provide any meaningful evaluation of the cost-effectiveness related to proposed energy efficiency control measures. Promising “consideration of plant thermal component efficiency” in the design process is no substitute for identifying proposed efficiency measures and evaluating their economic, energy, and environmental impacts. Nor is an assurance that the Project operator will follow manufacturers’ O&M guidelines a meaningful control measure, unless the Project operator had been planning to violate these guidelines as a matter of course before identifying this approach. In short, the Step 4 analysis of energy efficiency ignores virtually every component of a defensible BACT determination.

Response:

The response to the prior question discussed evaluation of energy efficiency measures and the EEMP in detail. As explained in that response, it is technically infeasible to identify or evaluate specific energy efficiency measures that will be employed in the final design because the measures selected will be dependent on facility-specific, as-built site conditions.

We have included language in the draft permit indicating that the operator follow manufacturer’s guidelines as a control measure because the engines, fans, and other equipment necessary to operate the CFB boiler may be operated under various conditions. There will also be guidelines on how to operate and maintain the equipment to achieve the most efficient operation for the desired electrical output. Thus the proposed language was not included in the draft permit because we believe the operator intended to operate the CFB boilers inconsistent with best operating practices.

³⁸ PSD and Title V Permitting Guidance for Greenhouse Gases, USEPA, March 2011, pg 21

³⁹ Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Industrial, Commercial, and Institutional Boilers, October 2010, USEPA, pg 25

⁴⁰ PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011, pg 22

Comment:

The Applicant has not shown that equally effective greenhouse gas controls cost only \$8/ton. In fact, the Applicant has not provided enough information on the control- and cost-effectiveness of other proposed BACT measures (biomass and energy efficiency) to even enable a relative comparison. The short-cut attempted in the GHG BACT Determination does not even attempt to comply with the requirements for this step of the BACT analysis.

Response:

There is very little, if any, reliable data regarding a cost effective level for greenhouse gas control costs. EPA makes this clear by stating, "...given that there is little history of BACT analyses for GHG at this time, there is not a wealth of GHG cost effectiveness data from prior permitting actions for a permitting authority to review and rely upon when determining what cost level is considered acceptable for GHG BACT."⁴¹

In their March 16, 2011 GHG BACT Supplement submittal, the applicant attempted to develop a cost effectiveness basis for GHGs by making comparisons between the greenhouse gas applicability threshold established in the Tailoring Rule and the average control cost effectiveness threshold of approximately \$8,000 per ton for a criteria pollutant.⁴² Using this information, Wolverine assumed that EPA was attempting to equate 100,000 tons of CO₂ to the 100 tons per year threshold for major sources defined in one of the 28 source categories in the PSD rules, and thus establish an \$8 per ton control cost threshold for GHGs. This cost effectiveness threshold was not used in the AQD evaluation of the GHG BACT Supplement.

EPA also suggests that for the economic analysis, "...it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner... As with all evaluations of economics, a permitting authority should explain its decisions in a well-documented permitting record."⁴³

As MDEQ evaluated the GHG BACT Supplement submitted by Wolverine for each step of the BACT process, all of the various control options dropped out for reasons other than economics, and by Step 4 of the process, we were left with only energy efficiency and biomass augmentation. Since the applicant was willing to accept conditions requiring both of these options under BACT, MDEQ elected to observe EPA's guidance, and there was no need to perform an economic evaluation.

Comment:

A thorough assessment of biomass availability must look at not simply how much forest growth occurs within the procurement area, but how much is actually available for purchase. Without considering any competing proposals, Wolverine's conclusion that there are unused logging residues of 220,000 dry tons per year which are available and sufficient to meet Wolverine's co-firing requirements are suspect.

According to the MTU Report, the Project will require 168,105 dry tons per year of biomass to sustain a 5% co-firing rate. The MTU Report concludes that 177,591 dry tons per year of logging residues, and 41,510 dry tons per year of "other removals" ("road and right-of-way

⁴¹ PSD and Title V Permitting Guidance for Greenhouse Gases, USEPA, March 2011, pg 43

⁴² (Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Federal Register, Vol. 75, No. 106, published June 30, 2010)

⁴³ PSD and Title V Permitting Guidance for Greenhouse Gases, USEPA, March 2011, pg 42

clearing and thinning treatments”), are available within the “bioshed,” defined as a 75-mile straight-line radius around the Project. However, the MTU Report does not provide any analysis of the cost of transportation of logging residues and “other removals” over these distances. The MTU Report thus does not establish that enough residues and “other removals” exist within an economically feasible transport radius of the Project to support even a 5% co-firing rate. Finally, the MTU Report fails even to mention or analyze competing demand for biomass feedstocks in the same bioshed.

Response:

The MTU study developed the 220,000 dry tons per year of available biomass using the USDA Timber Products Output database (USDA FIA-TPO 2006) and assumed an availability rate of 65%. As the report explains, this estimate is based on the “... ‘unused’ portion of annual removals, comprised of logging residues that are normally left on-site and ‘other’ removals, such as road and right-of-way clearing and thinning treatments.”⁴⁴ As described in the report, this estimate considered only the currently unused portion of biomass residues as material that is available to Wolverine. Estimating future additional demand for these unused residues would be pure conjecture.

However, the MTU study looked at both available unused forest residuals and other removals (such as brush clearing), and development of a sustainable biomass feedstock through dedicated energy crops. MTU estimates that there are an additional 980,000 dry tons per year of biomass that could be made available through development of a dedicated energy crop program.⁴⁵

Comment:

MDEQ’s calculation of the “parasitic load” of energy, and corresponding costs, required for CCS is also flawed. MDEQ claims that the “parasitic load” of energy required to power GHG capture at the Wolverine facility would “reduce the net generating capacity of the proposed CFB boiler by a minimum of 20%,” and thus would require additional output from the proposed design to achieve the desired energy production, generating additional emissions and additional costs to control those emissions. But a recent study shows that the energy penalty (parasitic load) of using MEA for carbon capture at a 500 MW plant is just less than 20%, while the penalty of using H3-1 at the same sized plant is approximately 16%. Thus, the “parasitic load” required for capture should be estimated to be 20% or less, and costs should be estimated accordingly.

Response:

There are no known full scale commercial CCS operations available to evaluate actual performance data on at this time. Therefore, all estimates are theoretical, or developed through pilot scale tests.

In the GHG BACT analysis, 20% was used as a lower limit because our research found such a wide range of estimates of the parasitic load from a variety of sources. One report from the Department of Energy estimates the parasitic load of a full CCS system at over 47%.⁴⁶ Another source indicates, “...parasitic energy requirement can range from around 25% for

⁴⁴ Biomass Co-Firing for the Wolverine Clean Energy Venture, January 30, 2008, pg 7

⁴⁵ Biomass Co-Firing for the Wolverine Clean Energy Venture, January 30, 2008, pg 8

⁴⁶ Existing Plants, Emissions and Capture - Setting CO2 Program Goals, Appendix C-5, April 20, 2009, DOE/NETL-2009/1366

post-combustion capture at a high efficiency ultra-supercritical coal plant up to over 37% for a typical subcritical plant"⁴⁷

The example cited in the comment was part of a Department of Energy network of seven Regional Carbon Sequestration Partnerships (RCSPs) that were created to develop the technology, infrastructure, and regulations to implement large-scale CO₂ sequestration in different regions and geologic formations within the Nation. The estimates of parasitic loads in the comment reflect the results of a Stage 1 capture trial, and do not include costs associated with sequestration, which can substantially increase both parasitic load and cost of control. In addition, because this is still a pilot study, there may be additional costs to scaling it to a full commercial operation, such as the costs of long term corrosion impacts. In addition, the presentation cited by the commenter as the source for the parasitic load estimates contains only conclusions of the study and does not provide the data used to develop these conclusions.

Thus MDEQ disagrees that the review was flawed.

Comment:

Wolverine BACT analysis contains the same deficiency that USEPA identified in its recent comments on the GHG Analysis for the Pacificorp Lake Side Power Plant: a failure to establish permit emission limits as PSD BACT for GHG emissions. The Wolverine BACT analysis also contains the same deficiencies that USEPA identified in its recent comments on the WE Energies Biomass Fueled Cogeneration Facility in Rothschild, Wisconsin. In those comments, USEPA specified that a GHG carbon dioxide equivalent in units of lbs/MWh be established as a BACT limit, the limit needed to be specific to the operating conditions, and the limit needed to specify whether it includes startup and shutdown periods.

Response:

The proposed Wolverine permit contains a limit of 2.1 lb CO₂e/KW-hr (gross output) that applies at all times, including startup and shutdown.

G. Material Handling

Comment:

The draft permit failed to incorporate a BACT analysis including covering storage piles.

Response:

MDEQ requested additional information from WCEV regarding the covered storage pile issue. WCEV submitted follow-up information on June 22, 2009 which addressed the covered storage pile comment. That information showed a cost per controlled ton of particulate matter to exceed \$4.4 million dollars; that value exceeds acceptable BACT cost parameters. Any emissions generated from uncovered storage piles would be fugitive in nature. Fugitive emissions – defined under MAPCR 336.1106(l) as those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening – meet the technological limitation standard included in the BACT definition and are

⁴⁷ Cost Analysis of Carbon Capture and Storage for the Latrobe Valley, February 28, 2010, Charles Kolstad and Daniel Young, Bren School of Environmental Science and Management, University of California, Santa Barbara, California)

subject to work practice and operation standards as BACT. The Fugitive Emissions Control Plan itself is the work practice standard necessary to satisfy BACT.

Comment:

Reliance on opacity, in place of numeric emission limits; fails to include enforceable BACT limits for haul roads. The comment further identifies the lack of any other haul roads in the draft permit to be in violation of BACT.

Response:

Haul road activities are subject to the requirements of the FECP. That plan requires, among other things, that unpaved travel surfaces be controlled by the application of water, sweeping, vacuuming, or other acceptable dust control method on a frequency sufficient to meet the visible emission opacity standard of five percent opacity. BACT is satisfied by the implementation of the FECP as a work process standard. There is no practical method to quantify emissions from haul roads. Therefore, a mass limit would be unenforceable.

Comment:

The PM10 modeling for the 24 hour PM10 NAAQS analysis and the increment analysis is based on unsupported and artificially low emission estimates for the O-N Mineral operations. This comment further identifies specific equipment inputs used in these modeling analyses as not representing worst-case emissions.

Response:

MDEQ disagrees with this comment. Commenter is correct that the PM10 modeling analysis must meet a worst case emissions standard meaning that the inputs for the computer modeling must reflect the highest level of air contaminant emitted from the modeled process. However the worst case standard must also reflect any controlling permit requirements for that equipment as well. Emissions calculations from the neighboring O-N Minerals operation are based on information taken from both MAERS emissions inventory and the current Permit to Install (PTI) 31-02A issued to the O-N facility. Calculated values from MAERS utilize high levels of control efficiencies. PTI 31-02A requires (among other requirements) that most of the limestone processing equipment operate within a building enclosure and emit no visible emissions from the operation. Other equipment and operations at the facility, including truck traffic and storage piles, are subject to a 5% opacity requirement and operational requirement from the facility's Fugitive Dust Control Plan. Proper operation of the required control equipment in PTI 31-02A would reflect a high degree of control efficiency. Worst case emissions must represent operation of the equipment under the terms of a lawfully issued PTI and cannot be based upon non-compliant operating conditions. Because the modeling inputs represent the upper end of allowable emissions from a lawfully permitted facility they correctly represent "worst-case" emissions.

Comment:

The PM10 modeling for the 24 hour PM10 MAAQS analysis and the Increment analysis is based on unsupported and artificially low emission estimates at the proposed coal plant. Commenter further identifies the assumed values for moisture content, wind speed, and control efficiencies as violating the "worst-case emissions" standard.

Response:

As discussed above, commenter is correct that the PM10 modeling analysis must meet a worst case emissions standard meaning that the inputs for the computer modeling must reflect the highest level of air contaminant emitted from the modeled process. However the worst case standard must also reflect any controlling permit requirements for that equipment as well. Permit conditions, including the FECP, require control of generated emissions. Assuming constant moisture content is an acceptable procedure when utilizing the AP-42 equations and emission factors. The assumed values used in this application fall within the acceptable range. Wind data was reviewed by AQD staff and deemed acceptable for this exercise. The permit conditions, including requirements for operating specific control equipment and operational requirements in the FECP, for this facility reflect high levels of control efficiency for material handling operations. Worst case emissions must represent operation of the equipment under the terms of a lawfully issued PTI and not be based upon non-compliant operating conditions.

Comment:

The PM10 modeling is based on an inappropriate and unjustified emissions figure for PM10 from haul roads. In particular, commenter cites the use of AP-42 emission factors found in Chapter 13 for silt content as too low and not reflective of worst case-emissions.

Response:

AQD staff reviewed the haul road emissions and assumptions contained within the application and concluded that those calculations are acceptable. Important to remember is that worst case emissions must represent operation of the equipment under the terms of a lawfully issued PTI and cannot be based upon non-compliant operating conditions. The haul roads are subject to both Special Conditions requiring an opacity limit of 5 % or less and the terms of a FECP, which requires wet sweeping for paved roads and wet/chemical suppression of dust for unpaved roads in order to meet required opacity limits. As these opacity requirements are quite stringent, the use of low silt content for emissions calculations is justified.

Comment:

It appears that Wolverine failed to include emission rates for the physical working of the storage piles in the PM10 modeling analysis. This must be done to accurately account for emissions.

Response:

Wolverine accounted for emissions from roadways, wind erosion and pile loading activities from the storage piles. Emissions associated with the physical working of the pile were not accounted for. This number is expected to be a minimal influence on the PM10 modeling analysis and not affect the results in a manner which violates the NAAQS or increment consumption from this facility. As a reference, Consumers Energy's recent permit for a larger facility calculated emissions from a storage pile as 0.18 lbs PM10 per hour. Those values extrapolated over the worst case operating scenario of 24 hrs/day and 7 days/week result in less than 0.8 tons of emissions per 12-month rolling time frame.

Comment:

A comment was received stating that “For EULIMESTONE, proposed permit does not include an operational limit on the maximum annual throughput of limestone. Limit is needed to substantiate several calculations such as the efficiency of the fabric filter and the wind erosion emissions calculation, which are based on the amount of limestone supply and usage/day.”

Response:

There are no underlying regulations requiring fabric filter efficiency and wind erosion calculations. As this proposed project is at a facility which is a source category designated through rulemaking under Section 302(j) of the CAA, fugitive emissions must be analyzed as part of the PSD-BACT review. The special conditions for EULIMESTONE include opacity limits, a requirement to install fabric filter control on collected exhaust streams, opacity monitoring requirements, and a requirement to implement a Fugitive Dust Control Plan upon operation of the equipment. All of these requirements fulfill BACT requirements. Opacity limits are specifically included in the definition of BACT. An emission limit of 0.00016 lbs PM per 1000 lbs of dry exhaust gas representing fabric filter control of the material handling exhaust stream is BACT for processes of this nature. Fugitive emissions – defined under MAPCR 336.1106(l) as those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening – meet the technological limitation standard included in the BACT definition and are subject to work practice and operation standards as BACT. The Fugitive Dust Emission Control Plan itself is the work practice standard necessary to satisfy BACT.

Comment:

Is it true that Wolverine will have the largest fuel pile with no dust suppression?

Response:

No, the proposed draft permit requires fuel piles to use dust suppression. More specific details of when and how often to use dust suppression will be developed in the Fugitive Emissions Control Plan (FECP) before the facility starts accepting fuels.

Comment:

The Permit only contains an opacity limit for roads in the section on limestone handling and thus fails to include enforceable BACT limits for truck traffic on all roads at the plant.

Response:

The AQD included the particulate emissions from the increased truck traffic on all the roadways on the facility when it evaluated total particulate emissions from the facility. The evaluation showed that the total particulate emissions from the facility are not expected to violate state and federal standards. In addition, the facility will have to comply with the FECP, which is authorized under the MDEQ State Rules 336.1371 and 336.1372.

H. Ancillary Equipment

Comment:

Proposed EUAUXBOILER emission limits are in lb/MMBtu. It is unclear how the source will demonstrate continuous compliance as the monitoring associated with these requirements is stack testing every 5 years. Explain how the source will demonstrate compliance, or incorporate into the permit additional monitoring and reporting requirements.

Response:

There is no continuous emissions monitoring required for the auxiliary boiler since the operating time will be limited. Required record keeping of fuel certifications and hours of operation along with stack testing to verify emission limits will be required to ensure compliance.

Comment:

For EUEMGGEN the proposed emission limits table does not include limits for SO₂ and VOC. Please add, with appropriate monitoring, recordkeeping and reporting to the permit.

Response:

The proposed draft permit for the EUEMGGEN emission unit does not include limits for sulfur dioxide. However it does include limits for the sulfur content in the fuel, monitoring and recordkeeping of fuel supplier certification records and hours of operation limit. When the emergency generator emissions were reviewed it was determined that BACT for an emergency generator (operating less than 500 hours per year burning fuel oil with a low sulfur content) was to limit only the sulfur content of the fuel since that is a limit which is more enforceable as practical manner. The fuel oil company is required to do an analysis of the fuel and to certify it. This allows more frequent monitoring and recordkeeping of the fuel that is burned.

The VOC emissions were evaluated to be about one ton per year for this size of a generator. Since hours of operation are limited, and the generator is operated with good combustion control techniques, it was determined that a VOC limit would not add any additional protection to health and the environment.

Comment:

For EUFIREPUMP, the proposed emission limits table does not include limits for CO, SO₂, and VOC. Please add, with appropriate monitoring, recordkeeping and reporting to the permit.

Response:

The proposed draft permit for the EUFIREPUMP emission unit does not include limits for SO₂, CO, or VOC. However, it does include limits for the sulfur content in the fuel, monitoring and recordkeeping of fuel supplier certification records and hours of operation limit. When the fire pump emissions were reviewed, it was determined that BACT for a fire pump (operating less than 500 hours per year burning fuel oil with a low sulfur content) was to limit only the sulfur content of the fuel since that is a limit which is more enforceable as practical manner. The fuel oil company is required to do an analysis of the fuel and to certify it. This allows more frequent monitoring and recordkeeping of the fuel which is burned.

The CO and VOC emissions were evaluated to be about a half ton per year each. Since the hours of operation are limited and the generator is operated with good combustion control techniques, it was determined that a CO and VOC limit would not add any additional protection to our health and environment.

Comment:

For EUBLACKSTART, the proposed emission limits table does not include VOC limits. Please add, with appropriate monitoring, recordkeeping and reporting to the permit.

Response:

The VOC emissions were evaluated to be about one ton per year. Since the hours of operation are limited and the generator is operated with good combustion control techniques, it was determined that a VOC limit would not add any additional protection to health and the environment.

Comment:

For FGCOOLINGTWR, the proposed permit does not include PM emission limits. Please add, with appropriate monitoring, recordkeeping and reporting to the permit.

Response:

The cooling towers emissions are minimal and BACT was considered to be the use of drift eliminators with a maximum drift rate of 0.0005 percent or less. The RBLC was reviewed and shows a number of entries of cooling towers at power generation facilities. The RBLC entries indicate a range of 0.001% to 0.0005% drift loss for MP10 emissions.

Comment:

Some cooling towers use algicides to control the formation of algae and molds. This could be a source that has not been considered and could emit VOC emissions.

Response:

To the extent algae growth does occur in the cooling towers it will be controlled by the addition of an oxidizing biocide. Oxidizing biocides typically consist of chlorine and bromine compounds. These oxidizing biocides do not contain VOCs and do not form VOCs as a part of the oxidizing reactions. Usage of oxidizing biocides depends on the type of oxidizing biocide used, specific conditions and the level of fouling. There are a number of oxidizing biocides which do not contain VOCs on the MDEQ-Surface Water Quality Division's (SWQD) "Water Treatment Additives with the Rule 57(2) Minimum Toxicity Data Base for Aquatic Life" list. Wolverine has stated that they will follow the MDEQ-SWQD guidelines regarding toxicity of water treatment additives as appropriate.

As stated on page 5-49 of the original application all VOC-related RBLC entries were for cooling towers at refineries. At refineries, the cooling towers would be serving equipment in VOC service (equipment that processes, transfers, or contains a VOC or mixture of VOCs), such as cracking towers and distillation columns which would have a potential of leaking VOC into the cooling media. AP-42, Section 5.1, lists a VOC emission factor specifically for refinery cooling towers due to hydrocarbon leaks into the cooling water system. On the other hand the AP-42, Section 13.4, provides a methodology for calculating PM emissions only from cooling towers in general. The cooling towers at WCEV will not be serving any

equipment in VOC service. As a result, there is no basis to expect that VOCs will leak into the cooling water system and result in VOC emissions from the cooling towers at WCEV.

Comment:

Is there any chlorine or other chemicals in the water vapor plume from the cooling towers and has this been studied?

Response:

Trace amounts of chlorine will be added to the cooling tower water to reduce algae growth on the tower equipment. Water evaporating from the tower will be mostly pure, except for the small presence of dissolved solids, which will exit the tower in particulate form. The tower's high efficiency drift eliminators will reduce these particulate emissions greatly. Technical studies on the fate of chlorine in cooling towers verify that the majority is consumed in reactions that kill the bacteria in the water and only insignificant amounts will be emitted to the air.

Comment:

Several comments were received regarding the use of water in the cooling towers and the effect that draining so much water from Lake Huron will have on the lake level. Why does the steam need to be discharged to the air instead of used in a cogeneration process?

Response:

The WCEV facility has been proposed to receive water, for the cooling towers from a portion of that which the Carmeuse quarry currently discharges into the creek running through the quarry property. Also, the facility has been designed to have zero liquid discharge (ZLD), which means there will not be any water discharged into Lake Huron. It will all be re-circulated back into the system.

Any steam generated is used in the process of generating electricity. The water going into the atmosphere is water vapor that results from evaporation from cooling the hot water prior to returning it to the system for recirculation. This is done to re-circulate the water continuously back into the system.

I. Control Equipment

Comment:

What securities/backups are required for emission control equipment failures? Will the emission control equipment be on at all times? What will happen if emission levels rise above the limit level? Will the boilers be required to shutdown, if that occurs?

Response:

The purpose of the malfunction abatement plan is to prevent failures from occurring by implementing a schedule for maintenance on all control equipment.

FGCFB special conditions IV.1 and IV.2 of the draft permit requires the permittee to operate the boilers at all times with the control devices listed. If for some reason, there is a malfunction of any of the control devices, then the appropriate actions as required in the

malfunction abatement plan (MAP) will be required to be implemented and could result in shutdown of the boiler(s).

Comment:

Why do you consider this proposed plant to be “clean” coal technology?

Response:

MDEQ has not labeled the proposed plant to be ‘clean’ coal technology. However, Clean Coal Technology is defined in the Michigan Department of Environmental Quality, Air Quality Division, Pollution Control Rule 336.2801(h) as any technology, including technologies applied at the pre-combustion, combustion, or post-combustion stage, at a new or existing facility which will achieve significant reductions in air emissions of sulfur dioxide or oxides of nitrogen associated with the utilization of coal in the generation of electricity, or process steam which was not in widespread use as of November 15, 1990. The control equipment that WCEV has proposed to use are selective non-catalytic reduction (SNCR) to control NOx emissions, limestone injection into the CFB boiler and polishing scrubber to control SO2 emissions, sorbent injection to control mercury emissions and fabric filter baghouse to remove particulates.

Comment:

Commenter asked if the NOx control for this facility is via an SNCR? What is an SNCR?

Response:

Yes, the CFB boilers will use a selective non-catalytic reduction (SNCR) system for NOx control. In an SNCR system, a reagent (ammonia or urea) is injected into the flue gas in the furnace of the boiler within an appropriate temperature window. The reagent reacts to reduce NOx into nitrogen and water.

J. Start-up and Shut-down Emissions

Comment:

Why does a base load facility need so many hours to start-up and shutdown?

Response:

The facility is permitted to operate continuously. However, there are expected times that the facility will need to shutdown for maintenance. It is also likely that the facility may encounter some occasional unexpected shutdowns. The duration of each startup and shutdown as well as emission estimates associated with unsteady state operation were compared to the manufacturer’s data and information from similar sources and found to be acceptable. In addition, the increase in emissions during startup and shutdown conditions was included in the modeling analysis and maximum impacts are still below the federal health standards. The company is also required to submit a plan that describes how emissions will be minimized during startup and shutdown conditions before operation of the equipment is allowed.

Comment:

The Draft Permit erroneously exempts Wolverine from NO_x and CO BACT limits during periods of startup, shutdown, and maintenance.

Response:

The commenter's claim that the draft permit exempts startup/shutdown operations from BACT limitations is incorrect. The permit contains BACT emission limits for NO_x and CO in units of pounds per hour that are applicable each hour the boiler operates, including periods of startup and shutdown. When measuring the NO_x concentration in parts per million (ppm) with a continuous emission monitor system (CEMs), a false high indication for NO_x occurs when very low CO₂ concentrations are measured. This data is used to calculate NO_x in pounds per million Btu (lb/MMBtu) emission rates during startup and shutdown operation. The NO_x emission rate equations are found in Method 19, Equation 19-7 of 40 CFR Part 60, Appendix A and Formula F-6 in Section 3.2 of 40 CFR Part 75, Appendix F. Mathematically, the last term in the equation causes the lb/MMBtu emission rate calculation to approach infinity as the measured diluent value approaches a value representative of zero heat input (i.e. 0.0 % when CO₂ is the monitored diluent). Thus, during periods of boiler startup and shutdown when the heat input and CO₂ concentrations are low (or high as would be the case if O₂ were being measured), the NO_x lb/MMBtu emission rates become artificially inflated. This is also the reason why the New Source Performance Standards (NSPS) for NO_x emission limit utility boilers, namely, 40 CFR Part 60, Subparts A and Da, Section 60.48Da(c), does not apply during periods of boiler startup, shutdown or malfunction. This same response also applies to CO emissions.

K. Annual Emissions

Comment:

Will the individual emissions of the Wolverine plant be less than or more than existing coal plants in Michigan? In what relationship?

Response:

Size for size, the proposed coal plant will emit less emissions than existing coal plants as a result of the best available control technologies that have been proposed.

Comment:

On September 18th, 2008, at a Presque Isle County Planning Commission meeting, Lee Sprague stated that "the MDEQ has not licensed a coal plant since 1984, they do not have the experience and expertise on hand to deal with even one permit, and they are bombarded with five of them." Is that true?

Response:

The MDEQ disagrees with the commenter. Even though there has not been a "new" coal plant permit issued in recent years, the AQD has had many permit applications for modifications at existing plants that has required us to keep up to date with what is happening around the nation with new and modified applications. The AQD participates on monthly calls with EPA Region 5 to discuss technologies, current rule revisions, new rules, recent court actions, BACT analyses, test methods, and policies.

Comment:

The generating capacity of Wolverine Power would be 600 megawatt, and the proposed generating capacity of Consumers Energy in Bay City would be 930 megawatt. Why is Wolverines plant proposing it would emit 820 pounds more of nitrogen oxide into the air than the Consumers Energy plant and Wolverine is 330 MW less capacity?

Response:

It is not clear what limits the commenter is referring to. Consumers Energy has a permit limit of 409.5 pounds per hour and Wolverine is proposing 281.1 pounds per hour, for NOx.

Comment:

Where and when has a plant of this size been permitted and are emissions data on record? Does it use like fuel?

Response:

There are a number of comparable existing plants with available emissions data. Information on the units was gathered including the unit characteristics, primary and secondary fuels, the permit date, the permit limits, the type of pollution control equipment and the level of emissions. The most similar CFB boilers (with the same type of controls) are Units 1 and 2 at JEA Northside Generating Facility located in Jacksonville, Florida. They are permitted to use coal and pet coke as fuel in the boilers, as Wolverine is proposing. The following table compares the JEA Northside facility with that of Wolverine.

<i>Pollutant</i>	<i>Wolverine</i>	<i>JEA Northside</i>
<i>SO2</i>	<i>0.06 lb/MMBtu (30-day), 0.05 lb/MMBtu (12month), 303 pph (24-hr)</i>	<i>0.15 lb/MMBtu (30 day), 0.20 lb/MMBtu (24-hr)</i>
<i>NOx</i>	<i>0.07 lb/MMBtu (30-day), 281.1 pph (24-hr)</i>	<i>0.09 lb/MMBtu (30-day)</i>
<i>H2SO4</i>	<i>0.003 lb/MMBtu (24-hr)</i>	<i>1.1 pph</i>
<i>PM</i>	<i>0.010 lb/MMBtu</i>	<i>0.011 lb/MMBtu</i>
<i>PM10</i>	<i>0.026 lb/MMBtu, 78.8 pph</i>	<i>0.011 lb/MMBtu **</i>
<i>PM2.5</i>	<i>0.024 lb/MMBtu, 72.7 pph excluding su/sd, 54.5 pph during su/sd</i>	<i>No limit</i>
<i>CO</i>	<i>0.15 lb/MMBtu (30-day), 744 pph (24-hr)</i>	<i>0.22 lb/MMBtu (24-hr)</i>
<i>**Limit is listed in the permit as PM/PM10.</i>		

Comment:

There were some incorrect emissions in the MDEQ Fact Sheet. They were as follows: VOCs were incorrectly calculated using the proposed pound per hour VOC limit of 17.8 rather than the intermediate load limit of 0.0066 lb/MMBTU. The lb/MMBTU limit effectively and enforceably limits the maximum VOC emissions from the CFB boilers to 122.6 tons/year. The current proposed limit is 33.3 tons/year less than the value listed in the Fact Sheet.

PM10 allowed emission was not updated in the Fact Sheet to reflect the final proposed PM10 limit of 0.026 lb/MMBTU. This PM10 limit was adjusted during the permit application review process based on the 112(g) analysis for the CFB boilers. As a result of this change, the allowed PM10 emissions from the CFB boilers were reduced from 717.0 tons/year to 690.1 tons/year. This limit is 26.9 tons/year less than the number listed in the Fact Sheet.

Response:

MDEQ has taken note of the discrepancy. However, as noted earlier, pages 3 -10, intermediate load limits are being removed from the permit.

Comment:

There are currently 88 operating coal-fired power plants in Michigan emitting 2,488 pounds of mercury, 91 million tons of Carbon Dioxide, and 300,000 tons of Sulfur Dioxide annually. Additional annual emissions from 8 new coal plants include: 232 pounds of Mercury, 13 million tons (or more) of Carbon Dioxide, 6776 tons of Sulfur Dioxide, and 2463 tons of additional particulate matter (soot).

Response:

MDEQ disagrees with the commenter. The MDEQ Mercury Strategy Staff Report in 2008 reported 21 plants. There have not been any new coal-fired power plants issued since the report was released. The report can be downloaded at:

http://www.michigan.gov/documents/deq/MDEQ_MSWSG_FinalReportJan2008.pdf_222256_7.pdf. The source of the commenter's information was not provided for MDEQ to determine the correctness of the figures.

Comment:

There are several contaminants emitted such as HCl, HF, and the presence of chlorine in the fuel oil for startups that could indicate formation of dioxins. Combination with 20% wood waste also could contribute to dioxin emissions. There is no discussion or determination of whether control of dioxins should be considered. Wood waste should also be prohibited that has been painted or chemically treated.

Response:

Dioxin formation is a by-product created during incineration, uncontrolled burning, and in some industrial processes. Just as combustion allows for formation of dioxins it also can destroy dioxins. The proper combustion temperature, combustion time, turbulence, and then quickly cooling the combustion gases minimizes the presence of certain metals known to promote dioxin formation. Wolverine will use good combustion control practices in the CFB boilers to minimize dioxins.

Comment:

When looking at real-world operations, CFB boilers do not emit less NOx than PC boilers. In fact, the opposite is the case. This is true whether one looks at uncontrolled emissions or controlled emissions.

Response:

Commenter did not provide any specific examples. NOx present in flue gas is a result of two sources: the oxidation of nitrogen compounds in the fuel (fuel NOx) and the reaction among nitrogen and oxygen in the combustion air (thermal NOx). CFB boiler combustion is a newer technology that provides greater fuel flexibility and more efficient heat transfer. The combustion temperature of a CFB boiler is a few hundred degrees lower than a PC boiler which favors lower NOx formation because the oxidation of the nitrogen in the fuel is suppressed.

Comment:

Emission limits for NOx, CO, SO2, and VOC in the proposed draft permit differ from that proposed in the application.

Response:

The Fact Sheet states that during the permit review process, the permittee submitted new information requesting different emission limits. The emissions limits, as presented in the draft permit for public review, reflect the most current information used in the application review. The MDEQ reviewed all emission limits and determined they meet all state and federal regulations.

L. Monitoring

Comment

The draft permit does not require PM CEMs, making the alleged BACT and MACT limits unenforceable.

Response:

A PM CEMS measures filterable PM only. The limits in the permit for particulate matter include both filterable and condensable particulate.

Comment:

How will compliance with the emission limits in the permit be demonstrated?

Response:

There are several ways in which emissions from a process may be monitored: stack sampling, continuous emissions monitors (CEMS), and continuous opacity monitoring (COMS).

Periodic stack tests are a required part of the annual Relative Accuracy Test Audits of the Continuous Emission Monitoring Systems at the facility. The stack testing requirements of the Permit to Install will also be included in a Renewable Operating Permit which the facility

must obtain. Also, General Condition No. 13 provides for additional stack testing not specifically included in the permit.

For air emissions, the act of sample collection involves the use of specialized equipment operated over an extended time period (usually three one-hour samples). Many process and control equipment variables must also be monitored during the stack test because of their possible effects on the air emissions. These may include fuel mixture content, steam output, startup/shutdown conditions, exhaust gas variables (moisture content, temperature, flow rate), and control equipment operating parameters. This sampling process provides a "snapshot" of the process emissions under known operating conditions. Three collected samples are then analyzed for each pollutant.

One objective of stack testing is to identify pollutant emission rates at "worst case" operating conditions. Operating parameters for the stack test are delineated in the stack test plan. Another objective is to identify measurable process and control system operating parameters which can be used to conclude that a process is operating within the allowed emission limits. For many small facilities of various types, a single stack test is conducted upon issuance of a Permit to Install. For many major sources of air emissions, stack testing is repeated every five years under a Renewable Operating Permit.

In addition to stack testing, Continuous Emission Monitoring Systems for NO_x, CO, SO₂, and exhaust gas oxygen content are required. Also, a Continuous Opacity Monitoring System (opacity indicates the presence of particulate matter) is required. These systems provide an indication of efficient and proper operation of the process, which means that emissions of all pollutants are reduced.

All records from stack testing and CEM systems must be kept on site for five years to demonstrate compliance with emission limits during site inspections from the district office.

Comment:

Where are the stack emission controls located on/in the stack?

Response:

It is unclear what the commenter is asking. There will be continuous emission monitoring (CEM) devices and continuous opacity monitoring (COM) device which are typically located after the control equipment and before the stack. These devices continuously monitor the amount of pollutants in the exhaust gases before the exhaust leaves the stack. There will be CEM devices for Nitrogen Oxide (NO_x), Sulfur dioxide (SO₂), and mercury. The COM will continuously monitor opacity coming from the stack.

There will also be pollutant emission controls, usually referred to as "control equipment" for NO_x, sulfur dioxide SO₂, and mercury. The NO_x control equipment proposed is selective non-catalytic reduction (SNCR), it will be located after the CFB boiler and will reduce NO_x emissions in the exhaust gases; to control SO₂ emissions, limestone injection will occur in the CFB boiler and a polishing scrubber will follow the SNCR; sorbent injection system to control mercury emissions will follow the polishing scrubber; and a fabric filter baghouse to remove particulates will follow the sorbent injection system.

Comment:

The consultant for Wolverine commented that an inadvertent error was made when formatting the proposed permit for public comment. During permit development, the MDEQ had language for Special Conditions relating to a schedule for the installation and operation of continuous emission monitoring (CEM) and emission testing of the new CFB boilers which provided, "Within 90 days of commencing commercial operation, as defined in 40 CFR 72.2, but no later than 12 months after commencement of initial startup of each boiler included in FGCFB." That language remains in proposed conditions VI.6, 8, 9, and 11 -16. However, it has been omitted from proposed conditions V. 3 – 9 and replaced with a requirement to conduct stack testing "within 180 days after commencement of initial startup..."

Response:

The MDEQ disagrees with commenter. The draft special conditions were reviewed and accepted by Wolverine before the comment period. MDEQ will leave the language as it was proposed during the comment period.

Comment:

Will the plant personnel be qualified or certified to perform the modification, installation, periodic maintenance, corrective maintenance, and routine calibrations of the monitoring devices? What standards/criteria are used in the certification? Who certifies the technician?

Response:

Generally when continuous emission monitoring devices are installed at a facility, plant personnel will operate and maintain the monitors. The monitors are required to be calibrated on a daily basis, so it is usually plant personnel who are assigned the calibration and maintenance functions. Plant personnel are trained in the operation and maintenance of the continuous emission monitors.

With regard to standards used in the certification of the monitors, the EPA has published performance specifications which must be followed in the certification of the monitors. These standards must be used in the installation and operation of the monitors.

In addition to the daily calibration of the monitors, the monitors are required to have calibration gas audits (CGAs) on a quarterly basis, and have relative accuracy test audits (RATAs) on an annual basis. The MDEQ participates in the RATAs and also reviews maintenance logs on the monitors.

The specific requirements for the installation calibration and maintenance of the continuous emission monitors are contained in special condition numbers VI.2 and VI.3 for the CFB boilers.

Comment:

How can we trust a company to do self monitoring?

Response:

The facility is a major source of emissions and is required to obtain a Renewable Operating Permit (ROP). The ROP requires the company to certify that they are in compliance with the terms and conditions of their permit semi-annually. Self monitoring is therefore not discretionary. The company will show compliance with their emission limitations through the use of continuous emission monitors, recordkeeping, and material analysis. Continuous

emission monitors are subject to federal requirements which require calibration as well as certification that the continuous emission monitors are calibrated and working properly. MDEQ staff will review this information and will verify that calibrations are done correctly by doing their own on site calibrations.

Records for emissions and process parameters will be stored and retained for at least five years and is shared with AQD. AQD has the ability to perform an independent analysis of the facility at any time.

The responsible official of any facility which has an ROP, can be criminally prosecuted, if the responsible official falsified information, or violated the terms and conditions of the operating permit.

Comment:

Who is to monitor the control system to ensure the proper operation and maintenance? Will the monitoring be continuous and will records be kept on file?

Response:

The company will be required to develop a preventative maintenance plan for the control system which includes the manufacturer's recommended guidelines. The AQD is responsible for approving this plan and overseeing its implementation. The company cannot operate the equipment until the plan is approved. The approved plan will be kept on file at the AQD Gaylord District Office and at the facility. When the AQD district personnel go to the facility for an inspection the company will be required to allow the AQD to view any records needed.

M. Compliance Testing

Comment:

Why is Wolverine allowed to choose their own stack testers? Shouldn't the DEQ do the testing?

Response:

Due to the large volume of testing required to analyze the air contaminants potentially being emitted from facilities all over Michigan, the MDEQ does not perform emissions testing. It is the responsibility of the owner of the facility to contract a certified tester and conduct and pay for emissions testing. However, the AQD's Technical Programs Unit reserves the right to witness the testing and thoroughly reviews test methods and reports before approving or denying results submitted by the tester.

Comment:

The testing requirements in the draft permit are written in a very vague way referring to Appendix A and/or a test plan submitted to the AQD. You should spell out exactly what test method you're going to require to be used.

Response:

The testing condition requires that a complete test plan be submitted 30 days prior to testing. The final plan must be approved by the AQD prior to testing. The testing methods are

proposed in the test plan, since the methods could change before the stack test is performed. If AQD does not agree with the test methods proposed then the permittee runs the risk of performing an unacceptable compliance test. This type of mistake is costly for the permittee, as they will still be expected to perform the compliance test with an approved method.

Comment:

The draft permit omits averaging times for numerous pollutant limits. Provisions allowing later determinations as to test protocols, time periods, and operating scenarios are not practically enforceable.

Response:

AQD permits normally do not contain averaging times for pollutant limits that will demonstrate compliance through stack testing. The test plan is required to be submitted 30 days prior to testing which will specify the test protocols, time periods (averaging times), and operating scenarios. This allows flexibility to choose the optimum and best methods.

Comment:

There are no provisions for future stack tests for toxic air contaminants. There is much uncertainty concerning the actual emission of toxic air contaminants. Testing for these pollutants must be performed before a permit is issued and annually thereafter. Testing must be conducted under worst case operating conditions. There is no monitoring for all pollutants emitted from the stack, so MDEQ doesn't know what's coming out of the stack.

Response:

As a part of the application review, AQD staff evaluated the generation, and potential emission, of toxic air contaminants. This evaluation included multiple fuels and fuel blends. The applicable regulations governing this review are; MAPCRs 336.1224 through 336.1232, and certain standards promulgated under Section 112 of the Clean Air Act. Individual toxic air contaminants testing/monitoring requirements were included as required by the applicable regulations. In some circumstances similar toxic air contaminants were grouped under a surrogate limit designed for compliance with the applicable regulations. All inclusive toxic air contaminants testing/monitoring requirements are not required under any of the applicable regulations.

N. Enforcement

Comment:

What process will be in place to ensure that the facility will not go above the allowed emissions? In the future if and when new information changes standards, how will enforcement change?

Response:

Changes will be addressed as the regulations dictate. Often there is a lead time allowed to implement new standards to allow for design and construction. Emission monitoring using Continuous Emission Monitors (CEMs), site inspections, and the Malfunction Abatement Plan (MAP) will all provide a way to measure compliance with allowed emissions. Also,

public reporting of emission concerns is an important part of compliance, as it alerts the AQD to investigate problems.

A MAP must include the following components as described in Rule 336.1911: a preventative maintenance program to minimize equipment malfunctions or failures, identify the process and emissions control equipment operating variables that will be monitored to detect a malfunction, and description of the corrective activities, methods, and/or operational changes to quickly restore normal operating conditions.

Comment:

How many times has a MDEQ permitted coal-fired power plant violated its air permit? Be specific with numbers and types of violations. How does violator correct air permit violations? Do they clean environment or pay a fine?

Response:

Air Quality Division (AQD) Field Section staff are located in eight district offices and two field offices. Additional investigatory and compliance support responsibilities are assigned to staff in the central Lansing office. Together, each year these AQD staff are responsible for conducting approximately 1,000 source inspections, investigating over 1,000 citizen complaints of air pollution, quality reviewing and assuring approximately 2,000 emission inventory reports, and sending out in excess of 500 Violation Notices. These AQD staff are responsible for evaluating the adequacy of the compliance programs to assure and maintain compliance, conducting oversight of over 200 stack tests and 750 in-stack monitors, resolving cited violations, and handling issuance, renewals and modifications for over 500 Title V Permits.

When, as a result of compliance assurance and source inspections, a violation is identified, staff advise the source of the violation, which is documented in a violation notice (previously identified as letters of violation). The AQD requires the source to take corrective action to resolve the violation and implement a corrective action plan identifying how the source will take preventative action to avoid repeating the cited violation.

The AQD reviews the magnitude, gravity, and frequency of each violation to determine if formal administrative action should be implemented to reflect and make enforceable the corrective action and enhance compliance assurance. Such an enforceable corrective action plan may be implemented promptly at the source, may be implemented and made enforceable under terms of the air use permit and/or may be implemented through an enforcement document such as an administrative order.

If a violation is deemed significant, the source is contacted by AQD's enforcement staff and a meeting is convened to discuss the cited violation and formalize a legally enforceable corrective action plan which is state and federally enforceable. In such an enforcement document a corrective action is required to be implemented, a settlement amount is required, and future violations may be subject to monetary sanctions.

The authority to assure compliance begins at the federal government through the USEPA. The USEPA has delegated to the state both the requirement and the authority to write air use permits and enforce the federal Clean Air Act Amendments (Act) requirements under the Natural Resources and Environmental Protection Act, Part 55 (Part 55) and the Rules promulgated under the Act. The Act and the Rules are incorporated into the State

Implementation Plan (SIP), which has been approved by the USEPA. Additional federal requirements have been conditionally delegated to the State. The State, through Part 55, has authority to issue permits, to enter orders, and to collect fines and penalties to assure compliance is attained and maintained, to preserve the health, safety and welfare of the citizens as well as the natural resources.

Comment:

The draft permit provisions that reference actions, steps, content or requirements contained in documents that fall outside of the permit are not enforceable. The specific stated concern is two permit references to compliance with manufacturers' specifications. Draft Permit EUEMGEN SC III.1 and EUFIREPUMP SC III.1.

Response:

The conditions that reference manufacturers' specifications are from the federal New Source Performance Standards (NSPS). One of the underlying applicable requirements for the special condition is 40 CFR 60.4206 which clearly states that "Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine."

Comment:

The word "satisfactory" is too subjective to be practically enforceable. The draft permit must be rewritten to delete all instances in which the term "satisfactory" is used.

Response:

The term "satisfactory" is used to allow for flexibility among different facilities. The MDEQ district inspector will review source records and the manner in which they are kept, to ensure the records are demonstrating compliance with the special conditions in the permit.

Comment:

A reference to operation of the turbine generator EUBLACKSTART emission unit with good pollution control practices is vague and unenforceable.

Response:

The condition that references good pollution control practices is from the federal New Source Performance Standards (NSPS). One of the underlying applicable requirements for the special condition is 40 CFR 60.4333 which clearly states in the NSPS that "You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction."

O. Rules and Regulations

Comment:

Emission limit requirement for the CFB boilers is missing for 40 CFR Part 60, Subpart Da which requires a 95% SO₂ emissions reduction based on a 30 day rolling average.

Response:

This requirement is an "OR" requirement. The regulation states that the emission unit must comply with 40 CFR 60.43Da(i)(1)(i) OR 40 CFR 60.43Da(i)(1)(ii). The draft permit requires compliance with 40CFR 60.43Da(i)(1)(i), which is that SO₂ must be less than 1.4 lb/MW-hr, as determined on a 30-day rolling average.

Comment:

How do the air quality regulations for power plants in Michigan compare with those of other states, particularly with those adjacent states?

Response:

All states must follow the federal rules and regulations which are consistent across states and their own state rules. Those regulations are Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Maximum Achievable Control Technology (MACT). All states have their own rules which are similar and cannot be any less stringent than federal rules and regulations.

P. Malfunction Abatement Plan (MAP)

Comment:

The condition requiring a malfunction abatement plan (MAP) also allows changes in the malfunction abatement plan (MAP) with the approval of the district supervisor. This allows the DEQ to make important changes to the permit without informing the public.

Response:

Changes in the MAP allow for flexibility and quick response to modifications in the operation of the plant which do not meet the definition of modification and therefore do not require a permit or public comment.

Comment:

The draft permit references a yet-to-be-developed malfunction abatement plan (MAP) and fugitive emissions control program (FECF) without specifying the contents of these. Consequently, the conditions referencing the MAP and FECF are not enforceable and violate the requirements of the CAA.

Response:

The MDEQ accurately informed the public during the public hearings and correctly referenced development of a MAP and FECF to be working documents referenced from within the permit but which can be fine tuned subsequently. It is standard practice to attach MAP and FECF documents to permits to allow inspectors and district supervisors to require additional modifications of these working documents once a facility is constructed, and during the time that it continues to operate thereafter. It is in the public and environment's best interests to retain these documents as references within the permit and the specifics of the MAP and FECF to be fine tuned over time to reflect changes in roadway maintenance and dust control techniques, equipment degradation and process refinements to assure protective measures are implemented and maintained in the best fashion. R 336.1911

("Rule 911") was most recently updated in March 2002, and has been part of the State Implementation Plan approved Rules since at least January 1980. R 336.1911(2) identifies in detail the minimum requirements of an acceptable MAP, which must be present before approval and with which it may practically enforceable.

Q. Emergencies and Safety Concerns

Comment:

Who should I contact to report a pollution emergency?

Response:

In addition to your local police and fire departments, you may call the Pollution Emergency Alert System (PEAS) at 1-800-292-4706. This telephone number is operated by MDEQ and is staffed 24 hours per day. Information received by the PEAS operator is quickly forwarded to the appropriate agencies.

Comment:

What types of accidental releases does the air-use permit address?

Response:

A facility is required to comply with all permit conditions, including emission limits, at all times. General Condition No. 7 requires the facility to notify the District Supervisor, AQD, of abnormal conditions or malfunctions resulting in certain types of emissions in excess of a standard or limitation lasting more than one hour. This condition places an additional burden on the facility to investigate and self-report malfunctions that cause excess emissions. Specifically, the facility is required to give the AQD a written summary of the actions taken to correct and prevent recurring malfunctions. These actions become a part of the facility's preventive maintenance and malfunction abatement plan.

Comment:

What is being done to address accidental releases?

Response:

The federal Clean Air Act requires that many facilities file risk management plans (RMPs) with the U.S. Environmental Protection Agency (U.S. EPA) and work with the local emergency planning committee to ensure response plans are in place in the event of an emergency. Local governments and local emergency response entities, such as fire and police departments, have primary responsibility for first response during emergencies. MDEQ works with the primary responders in a support role during emergencies. The company has developed an emergency preparedness plan with local officials, which must be continuously maintained and updated annually, and has a RMP on file with the U.S. EPA.

Air-use permits ensure that worst-case air emissions from process operations meet the appropriate air pollution control requirements and health protective limits. AQD's primary responsibility is to ensure that a facility complies with all applicable control technology and health standards. Permit conditions require that a facility properly install, operate, and maintain production and control equipment and require monitoring and recordkeeping of critical parameters to ensure that proper equipment operation is maintained. Also, permit

conditions require the installation of specific safety devices and require the periodic inspection of equipment for wear and deterioration. Once a permit has been issued, AQD makes periodic inspections and/or requires periodic stack testing to determine whether or not the facility is operating in compliance with its air-use permit. The draft permit conditions for this specific modified process include various monitoring, recordkeeping, reporting, and equipment/operational requirements in order to ensure compliance with emission limits. When violations are found, AQD takes enforcement action and makes certain they are addressed and corrections made promptly.

R. Public Participation Process

Comment:

How soon after the end of the comment period will the AQD make a finding and issue a permit to install and operate?

Response:

Any action on the proposed permit by MDEQ will occur after sufficient time to review and address all comments received during the comment period. Recognizing that the magnitude of this application far exceeds the average application this will likely be a lengthy process. Previously identified interested parties will receive notice of a final action.

Comment:

There is no ability of the public to have input on the adequacy of proposed pollution controls.

Response:

The primary purpose of the public comment period is to allow the public an opportunity to review the proposed project and provide input. Further, MDEQ posted all permit applicant submittals on the internet to better provide the public an opportunity to review all information and provide input.

Comment:

The notice of hearing does not mention the release of mercury from the proposed plant nor does it take into consideration cumulative impacts to human health from the combination of pollutants to be released.

Response:

The notice of hearing is only required by the Natural Resources and Environmental Protection Act, Act 451 of 1994, Part 55, Section 5511(3)(b) to include criteria pollutants that have been determined to increase significantly and the air impacts associated with the increase. Mercury is not a criteria pollutant so it was not listed in the notice of hearing. However, mercury, the air impacts and the detailed review the MDEQ did was included in the Public Participation Documents for Wolverine Power Supply Cooperative, Inc., Permit Application Number 317-07.

Comment:

Quoting your own documents (MDEQ's), "It has been preliminarily determined that the proposed installation of the facility will not violate any of the department's rules nor the national ambient air quality standards." What is the point of the public hearing?

Response:

The permit conditions reflect the rules and laws that the facility must operate under. The draft permit itself is the preliminary determination. The purpose of the public participation process is to obtain input on the preliminary determination from all affected parties, including the applicant and general public. This helps the decision-maker to make a more informed final decision on the permit application.

Comment:

Residents of Ontario should be asked for their approval of the new coal plant, since emissions will affect them too.

Response:

The following recipients received the draft permit to install and they were copied on the letter to Wolverine referencing when the public comment period for the proposed PSD source would begin: Mayor Beach Hall, City of Rogers City; Ms. Susan Rhode, Presque Isle County Clerk; Honorable Laurel Broten, Ontario Ministry of the Environment; Mr. Mike Moroney, Ontario Ministry of the Environment; Ms. Pamela Blakley, U.S. Environmental Protection Agency, Region 5; Ms. Laura Cossa, U.S. Environmental Protection Agency, Region 5; Mr. Jim Warner, Minnesota Pollution Control; Mr. Jeff Hanson, Wisconsin Bureau of Air Management; Ms. Laurel Kroack, Illinois EPA; Mr. Steve Blaser, Office of Air Quality IDEM; Mr. Robert Hodanbosi, Ohio EPA; Ms. Joyce E. Epps, Pennsylvania Bureau of Air Quality Control; Mr. David Shaw, New York Department of Environmental Conservation; Mr. John Bunyak, Isle Royale National Park Federal Land Manager Isle Royale National Park Superintendent; Ms. Sandra Silva, Seney National Wildlife Refuge Federal Land Manager; Seney National Wildlife Refuge Manager; and Ms. Janis Denman, MDEQ. Anyone is allowed to make comments on the proposed new plant during the comment period. The approval or denial of a draft permit to install is not based on a popularity vote, but rather information supporting state and federal regulations.

Comment:

Concern was expressed that a single non-elected official has the power to approve a permit.

Response:

Previous to Executive Order 1991-31, air use permits have been approved by the Air Pollution Control Commission. The Air Pollution Control Commission had been given the authority to approve air use permits. Executive Order 1991-31, which was signed by Governor John Engler on November 8, 1991, abolished the Air Pollution Control Commission and assigned their responsibilities to the Director of the Department of Natural Resources. Included in that transfer of responsibility was the approval of air use permits. Executive Order 1995-18, signed by Governor John Engler on July 31, 1995, created the MDEQ. The Air Quality Division was moved to the MDEQ. The powers of the director of the DNR as they related to approval of environmental permits were transferred to the Director of the MDEQ or the Director's delegated decision maker. Approval of permits is being done in accordance with these executive orders, which prescribe that one individual has the authority to approve

a permit. Even though one person is responsible for approving the permit, the technical review is still the same, and the permit has the same opportunity for public review and input that existed with the Air Pollution Control Commission.

Comment:

How can the decision be appealed?

Response:

Any person may appeal the permit decision as specified in the Natural Resources and Environmental Protection Act, Act 451 of 1994, Section 5505(8), which states:

Any person may appeal the issuance or denial by the department of a permit to install, a general permit, or a permit to operate authorized in rules promulgated under subsection (6), for a new source in accordance with section 631 of the revised judicature act of 1961, Act No. 236 of the Public Acts of 1961, being section 600.631 of the Michigan Compiled Laws. Petitions for review shall be the exclusive means to obtain judicial review of such a permit and shall be filed within 90 days after the final permit action, except that a petition may be filed after that deadline only if the petition is based solely on grounds arising after the deadline for judicial review. Such a petition shall be filed no later than 90 days after the new grounds for review arise. Appeals of permit actions for existing sources shall be in accordance with section 5506(14).

In addition, any person may file an action in a court of competent jurisdiction on a permit or consent order.

S. Miscellaneous

Comment:

Will Wolverine be able to commence construction based on this permit?

Response:

Yes, if the permit to install is approved then Wolverine will be able to commence construction.

Comment:

Has anyone from the DEQ that is involved in this permit visited the proposed site?

Response:

Yes. All AQD staff that attended the hearing visited the proposed site. In addition, the AQD Gaylord District Office Inspector responsible for inspecting the facility is familiar with the area and the site.

Comment:

What is the AQD required to know about the surrounding property use and what is their procedure for gathering and evaluating this information?

Response:

The location of any facility is an issue addressed by local government through the planning and zoning processes. The Air Quality Division does not control the selection of sites for industrial facilities nor does it have jurisdiction over local zoning issues. Site selection is done by the permit applicant. A site assessment is conducted by Air Quality Division staff as a part of the permit review process and air pollution impacts are reviewed.

Comment:

Does the State prefer or encourage the redevelopment of industrial land rather than to industrialize and take out of production agricultural land? Is the State persuaded by special-interest groups to make this decision?

Response:

As a regulatory agency, the Air Quality Division cannot exercise non-technical discretion in the issuance of air use permits. The permit review process is a technical review of the proposed air pollution source and issuance of the permit is based solely on expected compliance with all applicable state and federal rules and regulations.

Comment:

Shouldn't the residents have a right to decide if this plant should go here?

Response:

There is no legal mechanism which allows for popular votes on such proposals. Both the state and federal air pollution control laws are established by the legislative process and any changes to the regulations must go through this process. These laws are in place to protect public health and welfare. The role of the AQD is to implement the laws.

Comment:

Consideration of this permit should not be made until a popular vote is taken. The majority of the people believe the emissions from the plant will cause unreasonable interference with the comfortable enjoyment of life and property as stated in General Condition No. 6 of the draft permit terms and conditions.

Response:

There is no legal mechanism which allows for popular votes on such proposals. Both the state and federal air pollution control laws are established by the legislative process and any changes to the regulations must go through this process. The role of the AQD is to implement the laws.

General Condition No. 6 of the final permit specifically states that operation of the proposed process shall comply with Rule 901. Rule 901 states, in part, that "a person shall not cause or permit the emission of an air contaminant or water vapor in quantities that cause, alone or in reaction with other air contaminants...injurious effects to human health or safety...or unreasonable interference with the comfortable enjoyment of life and property." AQD staff takes into account the ability of a process to comply with Rule 901 as a part of the permit review and will not recommend approval of any application that they believe will not be able to comply with the Department's Rules for Air Pollution Control, including Rule 901. However, if a violation of Rule 901 should occur after the new process has commenced

operation, the final permit includes sufficient terms and conditions to allow the AQD to enforce this rule and address any such problems in the community.

Comment:

A decision on the permit should be delayed until the people have a chance to accept or reject the location of the plant.

Response:

The location of any facility is an issue addressed by local government through the planning and zoning processes. The Air Quality Division does not control the selection of sites for industrial facilities nor does it have jurisdiction over local zoning issues. Site selection is done by the permit applicant. The issuance of a Permit to Install by the AQD does not guarantee local site approval. A site assessment is conducted by Air Quality Division staff as a part of the permit review process and air pollution impacts are reviewed.

Comment:

Comments were received on the location of the plant near residential properties and tax breaks that the company may receive.

Response:

The location of any facility and taxing issues are subjects best addressed by local government through the planning and zoning processes. The Air Quality Division does not control the selection of sites for industrial facilities nor does it have jurisdiction over local zoning and taxing issues. Site selection is done by the permit applicant. The issuance of a Permit to Install by the AQD does not guarantee local site approval. A site assessment is conducted by Air Quality Division staff as a part of the permit review process and air pollution impacts are reviewed.

Comment:

Is the electricity generating plant warranted for this area or is it directly attributable to the deregulation of the power generating industry?

Response:

The AQD does not have authority to determine whether or not a type of industry is warranted for a specific area. The air permitting process involves a thorough review of the proposal and its impacts on the environment including whether or not the emissions will comply with state and federal health standards. Emissions from the plant will meet the NAAQS and the AQD health-based screening levels.

Comment:

The company should be required to provide salary for an MDEQ employee to monitor the record keeping and plant operation on a 24-hour basis.

Response:

There is no state or federal law that requires a facility to provide staff on a 24-hour basis to monitor plant operation. An AQD inspector is specifically assigned to inspect the equipment, review the records that the permit requires the facility to keep, and review the annual

emissions reports that the facility is required to submit. The facility is also required to submit test protocols and test results to the AQD for review and approval.

Comment:

Since the facility will be located in close proximity of so many people, they should be held to higher and broader standards than what smaller industry is held to.

Response:

All processes that have the potential to emit an air contaminant are required to comply with all applicable state and federal rules and regulations. Most air pollution control laws are based on the amount of emissions from the process. As a result, larger facilities are often subject to more regulations that are often quite stringent. Such is the case with Wolverine. In addition, all facilities that go through the permit review process must comply with national health standards and the AQD health-based screening levels regardless of the location. Maximum impacts from the facility are below all applicable health standards.

Comment:

Can the DEQ and the people of the State of Michigan trust the company to follow regulations and do the required reporting?

Response:

The AQD cannot recommend a permit for approval if it is determined that the proposal cannot comply with all applicable state and federal rules and regulations. The company's proposed installation was reviewed and compared to other similar sources throughout the nation. Any information that seems unreasonable or inadequate is questioned and challenged. The permit is written using the best available and most updated data on the proposed source. Emission levels are compared with levels from similar sources throughout the United States and with actual test data to determine if they are reasonable and can be achieved. If the Permit to Install is violated, the regulations allow for AQD staff to take enforcement action against a facility.

Comment:

Would AQD staff allow this facility in their neighborhood?

Response:

Like most citizens, AQD staff places a high priority on residing and raising their families in a healthy environment. We share the concerns voiced by impacted residents, and we apply the air pollution control laws to help ensure public health protection. We are all exposed to air pollutants to some degree. From what we do know about the emissions and health risks associated with such facilities, we ensure that the allowed emissions do not pose unacceptable health risks, as required under the law. There are many aspects beyond effects on air quality that would be issues in siting this type of facility in a neighborhood. These include things that are not within AQD's jurisdiction such as effects on property values, noise, traffic, etc. All of these are reasonable concerns that most people would want answered and addressed. The answers to these questions would obviously impact anyone's response as to whether or not they would accept an industry in their neighborhood. While these are important issues, the permit under review by the Air Quality Division is meant to address the aspect of effects on ambient air quality. AQD staff is required to make sure that

all permits issued by the State comply with all applicable state and federal regulations. These regulations are designed to protect human health and the environment. The decision as to whether to approve or disapprove an air permit application in any neighborhood, regardless of location, would depend on whether or not the proposed facility would comply with all such applicable air regulations.

T. Other Comments Received – Not Regulated by the AQD

Comment:

When and where will other environmental issues such as water, heavy metals, fuel storage, etc. be addressed?

How can you not mandate a Water Quality permit first, although the plant will likely use billions of gallons of water, perhaps much of it dewatering water of questionable quality from the quarry or perhaps, mostly from Lake Huron.

Response:

The proposed permit is for the prescribed purpose of assuring compliance with Part 55 of 1994 PA 451 only. General Condition 9 of the proposed permit specifically states that "Approval of this permit does not obviate the necessity of obtaining such permits or approvals from other units of government as required by law." Wolverine has stated that the plant is being designed for zero discharge and that a NPDES (National Pollutant Discharge Elimination System (NPDES) permit, will not be required. Wolverine has also stated that a timely permit application for ash disposal will be made to the MDEQ when required for plant operation. The air permit application addresses permitting requirements for fuel storage and handling. With the possible exception of storm water discharge permitting, Wolverine has again stated that a timely permit application for a storm water discharge permit will be made, if necessary, to the MDEQ when required for plant operation.

Comment:

Petroleum coke results in especially high amounts of ash compared to coal, in the range of twice as much fly ash and 65 percent more bottom ash.

Response:

This activity is not within the regulatory authority of this permit. Solid waste disposal is subject to separate permitting. This permit is limited to the activities at the source as they pertain to air emissions, which the emissions and impacts from the proposed facility were evaluated and determined to comply with all applicable regulations which are designed to ensure an adequate level of protection for the environment and public health.