AIR EMISSION PERMIT NO. 13700028- 005

IS ISSUED TO

The City of Virginia,
The Virginia Public Utilities Commission, and
Laurentian Energy Authority LLC
618 2nd Street South
Virginia, St. Louis County, MN 55792

The emission units, control equipment and emission stacks at the stationary source authorized in this permit are as described in the following permit application(s):

Permit Type	Application Date	Issuance Date	Action Number
Total Facility Operating Permit	09/18/1995	02/05/1998	001
Major Amendment	02/02/1998	12/22/1998	002
Major Amendment	02/08/1999	04/06/1999	003
Major Amendment	12/24/2001	10/31/2002	004
Major Amendment/Reissuance	01/01/2004 08/31/2004	See below	005

This permit authorizes the permittee to modify and operate the stationary source at the address listed above unless otherwise noted in Table A. The permittee must comply with all the conditions of the permit. Any changes or modifications to the stationary source must be performed in compliance with Minn. R. 7007.1150 to 7007.1500. Terms used in the permit are as defined in the state air pollution control rules unless the term is explicitly defined in the permit.

Permit Type: Federal; Pt 70 Reissuance/NSR Authorization
40 CFR 52.21 Construction Authorization Issue Date: June 30, 2005
40 CFR 52.21 Construction Authorization Effective Date: June 30, 2005
40 CFR Part 70 Operating Conditions Issuance Date: June 30, 2005
Expiration: June 30, 2010
Title I Conditions do not expire.

Richard J. Sandberg, Manager
Air Quality Permits Section
Industrial Division

for Sheryl A. Corrigan
Commissioner
Minnesota Pollution Control Agency

TABLE OF CONTENTS

NOTICE TO THE PERMITTEE:

Your stationary source may be subject to the requirements of the Minnesota Pollution Control Agency's (MPCA) solid waste, hazardous waste, and water quality programs. If you wish to obtain information on these programs, including information on obtaining any required permits, please contact the MPCA general information number at:

Metro Area	(651) 296-6300
Outside Metro Area	1-800-657-3864
TTY	(651) 282-5332

The rules governing these programs are contained in Minn. R. chs. 7000-7105. Written questions may be sent to: Minnesota Pollution Control Agency, 520 Lafayette Road North, St. Paul, Minnesota 55155-4194.

Questions about this air emission permit or about air quality requirements can also be directed to the telephone numbers and address listed above.

PERMIT SHIELD:

Subject to the limitations in Minn. R. 7007.1800, compliance with the conditions of this permit shall be deemed compliance with the specific provision of the applicable requirement identified in the permit as the basis of each condition. Subject to the limitations of Minn. R. 7007.1800 and 7017.0100, subp. 2, notwithstanding the conditions of this permit specifying compliance practices for applicable requirements, any person (including the Permittee) may also use other credible evidence to establish compliance or noncompliance with applicable requirements.

FACILITY DESCRIPTION:

The city of Virginia Department of Public Utilities is a citizen-owned utility providing steam and electricity to businesses and residents of the local Virginia area. The department currently operates any combination of three boilers using coal and/or natural gas as fuel. The three boilers are referred to as Boiler No. 7, 9, and No. 10. Boiler No. 10 is a natural gas fired boiler. Boiler No. 7 can burn both coal, sub-bituminous or bituminous, and natural gas. Boiler No. 9 is a coal only boiler. Boiler 8 is physically disconnected from the Utility System.

In addition to being a reissuance of the total facility permit this permit authorizes the installation of a wood fired boiler to be used for district heating and electric generation. Also authorized with this permit action are the installation of wood handling and storage equipment. This modification is subject to federal new source review.

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Table A contains limits and other requirements with which your facility must comply. The limits are located in the first column of the table (What To do). The limits can be emission limits or operational limits. This column also contains the actions that you must take and the records you must keep to show that you are complying with the limits. The second column of Table A (Why to do it) lists the regulatory basis for these limits. Appendices included as conditions of your permit are listed in Table A under total facility requirements.

Subject Item: Total Facility

What to do	Why to do it
The Permittee shall comply with the General Conditions listed in Minn. R. 7007.0800, subp. 16.	Minn. R. 7007.0800, subp. 16
Fugitive Emissions: Do not cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne. Comply with all other requirements listed in Minn. R. 7011.0150.	Minn. R. 7011.0150
Air Pollution Control Equipment: Operate all pollution control equipment whenever the corresponding process equipment and emission units are operated, unless otherwise noted in Table A.	Minn. R. 7007.0800, subp. 2; Minn. R. 7007.0800, subp. 16(J)
Operation and Maintenance Plan: Retain at the stationary source an operation and maintenance plan for all air pollution control equipment.	Minn. R. 7007.0800, subp. 14 and Minn. R. 7007.0800, subp. 16(J)
Shutdowns: Notify the Commissioner at least 24 hours in advance of a planned shutdown of any control equipment or process equipment if the shutdown would cause any increase in the emissions of any regulated air pollutant. If the owner or operator does not have advance knowledge of the shutdown, notification shall be made to the commissioner as soon as possible after the shutdown. However, notification is not required in the circumstances outlined in Items A, B and C of Minn. R. 7019.1000, subp. 3. At the time of notification, the owner or operator shall inform the Commissioner of the cause of the shutdown and the estimated duration. The owner or operator shall notify the Commissioner when the shutdown is over. In addition, the notification for the Wood Fired Boiler is due by letter within 7 days of the shutdown if the shutdown was not consistent with the startup, shutdown and malfunction plan, and any applicable emission limitation was exceeded.	Minn. R. 7019.1000, subp. 3 and Table 9 to Subp. DDDDD of Part 63
Breakdowns: Notify the Commissioner within 24 hours of a breakdown of more than one hour duration of any control equipment or process equipment if the breakdown causes any increase in the emissions of any regulated air pollutant. The 24-hour time period starts when the breakdown was discovered or reasonably should have been discovered by the owner or operator. However, notification is not required in the circumstances outlined in Items A, B and C of Minn. R. 7019.1000, subp. 2. At the time of notification or as soon as possible thereafter, the owner or operator shall inform the Commissioner of the cause of the breakdown and the estimated duration. The owner or operator shall notify the Commissioner when the breakdown is over. In addition, the notification for the Wood Fired Boiler is due by letter within 7 days of the breakdown if the breakdown was not consistent with the startup, shutdown and malfunction plan, and any applicable emission limitation was exceeded.	Minn. R. 7019.1000, subp. 2 and Table 9 to Subp. DDDDD of Part 63
Refer to the EU006 requirements table for additional reporting requirements when actions taken are not consistent with the procedures specified in the EU007 startup, shutdown, and malfunction plan, and EU006 exceeds an applicable emission limitation.	continued from above
Monitoring Equipment: Install or make needed repairs to monitoring equipment within 60 days of issuance of the permit if monitoring equipment is not installed and operational on the date the permit is issued.	Minn. R. 7007.0800, subp. 4(D)
Monitoring Equipment Calibration: Annually calibrate all required monitoring equipment (any requirements applying to continuous emission monitors are listed separately in this permit).	Minn. R. 7007.0800, subp. 4(D)
Operation of Monitoring Equipment: Unless otherwise noted in Tables A, B, and/or C, monitoring a process or control equipment connected to that process is not necessary during periods when the process is shutdown, such as for system breakdowns, repairs, calibration checks, and zero and span adjustments (as applicable). Monitoring records should reflect any such periods of process shutdown.	Minn. R. 7007.0800, subp. 4(D)
Circumvention: Do not install or use a device or means that conceals or dilutes emissions, which would otherwise violate a federal or state air pollution control rule, without reducing the total amount of pollutant emitted.	Minn. R. 7011.0020
Performance Testing: Conduct all performance tests in accordance with Minn. R. ch. 7017 unless otherwise noted in Tables A, B, and/or C.	Minn. R. ch. 7017

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Limits set as a result of a performance test (conducted before or after permit issuance) apply until superseded as specified by Minn. R. 7017.2025 following formal review of a subsequent performance test on the same unit.	Minn. R. 7017.2025
Notification of Deviations Endangering Human Health or the Environment: As soon as possible after discovery, notify the Commissioner or the state duty officer, either orally or by facsimile, of any deviation from permit conditions which could endanger human health or the environment.	Minn. R. 7019.1000, subp. 1
Operation Changes: In any shutdown, breakdown, or deviation the Permittee shall immediately take all practical steps to modify operations to reduce the emission of any regulated air pollutant. The Commissioner may require feasible and practical modifications in the operation to reduce emissions of air pollutants. No emissions units that have an unreasonable shutdown or breakdown frequency of process or control equipment shall be permitted to operate.	Minn. R. 7019.1000, subp. 4
Notification of Deviations Endangering Human Health or the Environment Report: Within 2 working days of discovery, notify the Commissioner in writing of any deviation from permit conditions which could endanger human health or the environment. Include the following information in this written description: 1. the cause of the deviation; 2. the exact dates of the period of the deviation, if the deviation has been corrected; 3. whether or not the deviation has been corrected; 4. the anticipated time by which the deviation is expected to be corrected, if not yet corrected; and 5. steps taken or planned to reduce, eliminate, and prevent reccurrence of the deviation.	Minn. R. 7019.1000, subp. 1
Application for Permit Amendment: If you need a permit amendment, submit application in accordance with the requirements of Minn. R. 7007.1150 through Minn. R. 7007.1500. Submittal dates vary, depending on the type of amendment needed.	Minn. R. 7007.1150 through Minn. R. 7007.1500
Extension Requests: The Permittee may apply for an Administrative Amendment to extend a deadline in a permit by no more than 120 days, provided the proposed deadline extension meets the requirements of Minn. R. 7007.1400, subp. 1(H).	Minn. R. 7007.1400, subp. 1(H)
Emission Fees: due 60 days after receipt of an MPCA bill	Minn. R. 7002.0005 through Minn. R. 7002.0095
Inspections: Upon presentation of credentials and other documents as may be required by law, allow the Agency, or its representative, to enter the Permittee's premises, to have access to and copy any records required by this permit, to inspect at reasonable times (which include any time the source is operating) any facilities, equipment, practices or operations, and to sample or monitor any substances or parameters at any location.	Minn. R. 7007.0800, subp. 9(A)
Record keeping: Maintain records describing any insignificant modifications (as required by Minn. R. 7007.1250, subp. 3) or changes contravening permit terms (as required by Minn. R. 7007.1350, subp. 2), including records of the emissions resulting from those changes.	Minn. R. 7007.0800, subp. 5(B)
Record keeping: Retain all records at the stationary source for a period of five (5) years from the date of monitoring, sample, measurement, or report. Records which must be retained at this location include all calibration and maintenance records, all original recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Records must conform to the requirements listed in Minn. R. 7007.0800, subp. 5(A).	Minn. R. 7007.0800, subp. 5(C)
Noise: The Permittee shall comply with noise standards set forth in Minn. R. 7030.0010 to 7030.0080 at all times during operation of any emission units. This is a state requirement only and is not federally enforcable.	Minn. R. 7030.0010-7030.0080
The Permittee may be required to submit a Risk Management Plan (RMP) under the federal rule, 40 CFR Part 68 which was promulgated on June 20, 1996. The rule will require each owner or operator of a stationary source, at which a regulated substance is present above a threshold quantity in a process, to design and implement an accidental release prevention program. The RMPs must be submitted to a centralized location as specified by US EPA. The Permittee may obtain the RMP submittal information at http://www.epa.gov/swercepp or by calling 1-800-424-9346. These requirements must be complied with no later than the latest of the following dates: (1) June 21, 1999; (2) Three years after the date on which a regulated substance is first listed under 40 CFR Section 68.130; or (3) The date on which a regulated substance is first present above a threshold quantity in a process.	40 CFR Part 68

Performance Test Notifications and Submittals (or Fuel Analyses for those pollutants not tested for); Performance Test Notification (written): due 30 days before each Performance Test Performance Test Plan: due 30 days before each Performance Test Performance Test Pre-Test Meeting: due 7 day before each Performance Test Performance Test Report: due 45 days after each Performance Test Performance Test Report - Microfiche Copy or CD: due 105 day after each Performance Test. The Notification, Test Plan, and Test Report may be submitted in alternative format as allowed by Minn. R. 7017.2018. For the Wood Fired Boiler, the Performance Test Report or Fuel Analysis Report must include the information in 40 CFR Section 63.7545(e).	Minn. R. 7017.2030, subp. 1-4; Minn. R. 7017.2018, Minn. R. 7017.2035, subp. 1-2, 40 CFR Section 63.7(b)(1) and (3), 40 CFR Section 63.7545(e)
Comply with Subp. DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, as applicable, by September 13, 2007 for Boilers 7, 9, and 10. Also comply with applicable requirements of 40 CFR Part 63, Subp. A.	40 CFR Subp. DDDDD
AMBIENT STANDARDS	hdr
The Permittee shall comply and demonstrate compliance with National Primary and Secondary Ambient Air Quality Standards, 40 CFR pt. 50 and the Minnesota Ambient Air Quality Standards, Minn. R. 7009.0010 to 7009.0800.	40 CFR pt. 50; Minn. Stat. Sec. 116.07, subds. 4a and 9; Minn. R. 7007.0100, subps. 7A, 7L and 7M; Minn. R. 7007.0800, subps. 1, 2, and 4; Minn. R. 7009.0010-7009.0080.
Parameters Used in Modeling: The stack heights, emission rates, and other parameters used in the dispersion modeling are listed in the Appendix of this permit. The Permittee must submit to the Commissioner for approval any revisions of these parameters and must wait for a written approval before making such changes. The information submitted must include, at a minimum, the locations, heights and diameters of the stacks, locations and dimensions of nearby buildings, the velocity and temperatures of the gases emitted, and the emission rates. The plume dispersion charateristics due to the revisions of the information must be equivalent to or better than the dispersion charateristics modeled. The Permittee shall demonstrate this equivalency in the proposal. If the information does not demonstrate equivalent or better dispersion characteristics, or if a conclusion cannot readily be made about the dispersion, the Permittee must remodel.	Title I Condition: 40 CFR Section 52.21(k); Minn. R. 7007.3000
For changes that do not involve an increase in an emission rate and that do not require a permit amendment, this proposal must be submitted as soon as practicable, but no less than 60 days before beginning actual construction of the stack or associated emission unit. For changes involving increases in emission rates and that require a minor permit amendment, the proposal must be submitted as soon as practicable, but no less than 60 days before beginning actual construction of the stack or associated emission unit. For changes involving increases in emission rates and that require a permit amendment other than a minor amendment, the proposal must be submitted with the permit applicaiton.	Title I Condition: 40 CFR Section 52.21(k); Minn. R. 7007.3000

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **GP 001 Boilers 7 and 9 SO2 limits**

Associated Items:
CE 001 Centrifugal Collector - Medium Efficiency
CE 002 Electrostatic Precipitator - High Efficiency
CE 003 Electrostatic Precipitator - High Efficiency
EU 001 Boiler #7
EU 003 Boiler #9
SV 002 Boiler No. 7
SV 003 Boiler No. 9

What to do	Why to do it
Sulfur Dioxide: less than or equal to 2.5 lbs/million Btu heat input using 1-Hour Average when only one of the emission units in GP 001 is combusting coal.	Minn. R. 7009.0020 to ensure facility does not cause or contribute to a violation of the sulfur dioxide ambient air standard in Minn. R. 7009.0080; meets requirements of Minn. R. 7011.0510, subp. 1
Sulfur Dioxide: less than or equal to 1.60 lbs/million Btu heat input using 1-Hour Average when both EU 001 and EU 003 are combusting coal. This SO2 limit applies individually to each emission unit.	Minn. R. 7009.0020 to ensure facility does not cause or contribute to a violation of the sulfur dioxide ambient air standard in Minn. R. 7009.0080; meets requirements of Minn. R. 7011.0510, subp. 1
Coal Combustion Monitoring: The Permittee shall record the start and stop dates and times of all coal combustion periods in EU 001 and EU 003. The Permittee may use the data from the SO2 CEM for EU 001 (on SV 002) and the SO2 CEM for EU 003 (on SV 003) to meet this recordkeeping requirement providing the CEM data continuously specifies the time and date. However, when either or both of the CEMs malfunction, the Permittee shall keep a written log of coal combustion in EU 001 and/or EU 003 in place of CEM data, during the CEM malfunction.	Minn. R. 7007.0800, subp. 4

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **GP 002 Boilers 7, 9, and 10 and makeup air heater**

Associated Items: EU 001 Boiler #7

EU 003 Boiler #9

EU 004 Boiler #10

EU 005 Makeup Air Heater

What to do	Why to do it
Nitrogen Oxides: less than 73.08 tons/month using 12-month Rolling Average basis.	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR Section 52.21
Recordkeeping: by the 15th day of each month, the Permittee shall record the following information: 1) tons of coal burned in EU 001 during the previous month; 2) tons of coal burned in EU 003 during the previous month; 3) total mmcf (million cubic feet) of natural gas burned in EU 001 during the previous month; 4) total monthly NOx emissions for EU 004 and EU 005 as measured by NOx CEMS. The Permittee shall use these fuel usage records, NOx emissions data, and Equation 1 to determine monthly facility NOx emissions.	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR Section 52.21; Minn. R. 7007.0800, subp. 5
By the 15th day of each month the Permittee shall calculate and record the monthly NOx emissions using Equation 1: NOx emissions = EF1c(A) + EF1ng(B) + EF3c(C) + y EF1c = 0.007 (EU 001 emission factor for coal; tons NOx/ton coal combusted) EF1ng = 0.275 (EU 001 emission factor for natural gas; tons NOx/mmcf natural gas combusted) EF3c = 0.007 (EU 003 emission factor for coal; tons NOx/ton coal combusted) A = tons of coal burned in EU 001 during the month B = mmcf natural gas burned in EU 001 during the month C = tons of coal burned in EU 003 during the month y = monthly total EU 004 and EU 005 NOx emissions determined by NOx CEMS By the 15th day of each month the Permittee shall calculate and record the monthly 12-month rolling average NOx emission rate. The monthly 12-month rolling average shall be determined by summing the monthly NOx emission rates (determined using the above equation) for the previous 12 months, and dividing by 12.	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR Section 52.21; Minn. R. 7007.0800, subp. 4.B.
Revision of Equation 1 Emission Factors: All Equation 1 emission factors shall be revised based on the results of each performance test. The Permittee shall use the most-recent performance test-revised emission factor for calculating emissions, upon receipt of written notification from the MPCA that the performance testing results were valid. For the interim period prior to receipt of any written MPCA notification, the Permittee shall use the factors defined above for Equation 1 in this permit.	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR Section 52.21

TABLE A: LIMITS AND OTHER REQUIREMENTS

07/11/05

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **GP 003 Material Handling Baghouses**

Associated Items:
CE 010 Fabric Filter - Low Temperature, i.e., T<180 Degrees F
CE 011 Fabric Filter - Low Temperature, i.e., T<180 Degrees F
CE 012 Fabric Filter - Low Temperature, i.e., T<180 Degrees F
CE 013 Fabric Filter - Low Temperature, i.e., T<180 Degrees F
CE 014 Fabric Filter - Low Temperature, i.e., T<180 Degrees F
CE 015 Fabric Filter - Low Temperature, i.e., T<180 Degrees F
CE 016 Fabric Filter - Low Temperature, i.e., T<180 Degrees F

What to do	Why to do it
No visible emissions allowed.	Title I Condition: to ensure compliance with PM10 BACT limit
Visible Emissions: The Permittee shall check the fabric filter stacks for any visible emissions once each day of operation during daylight hours. During inclement weather, the Permittee shall read and record the pressure drop across the fabric filters, once each day of operation.	Title I Condition: to ensure compliance with PM10 BACT limit
Recordkeeping of Visible Emissions and Pressure Drop. The Permittee shall record the time and date of each visible emission inspection or pressure drop reading, and whether or not any visible emissions were observed, and whether or not the observed pressure drop was within the range specified in this permit. Pressure Drop Range for CE010: CE011: CE012: CE013: CE014: CE015: CD016: The pressure drop range for each baghouse shall be submitted, along with an application for a major amendment, once a vendor is chosen. The manufacturer's information must be submitted with the application.	Title I Condition: to ensure compliance with PM10 BACT limit
The Permittee shall operate and maintain the fabric filter at all times that any emission unit controlled by the fabric filter is in operation. The Permittee shall document periods of non-operation of the control equipment when the emission unit is in operation.	Title I Condition: to ensure compliance with PM10 BACT limit
Corrective Actions: The Permittee shall take corrective action as soon as possible if any of the following occur: - visible emissions are observed; - the recorded pressure drop is outside the required operating range; or - the fabric filter or any of its components are found during the inspections to need repair. Corrective actions shall return the pressure drop to within the permitted range, eliminate visible emissions, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the O & M Plan for the fabric filter. The Permittee shall keep a record of the type and date of any corrective action taken for each filter.	Minn. R. 7007.0800, subp. 4, 5, and 14
Monitoring Equipment: The Permittee shall install and maintain the necessary monitoring equipment for measuring and recording pressure drop as required by this permit. The monitoring equipment must be installed, in use, and properly maintained when the monitored fabric filter is in operation.	Minn. R. 7007.0800, subp. 4
Periodic Inspections: At least once per calendar quarter, or more frequently as required by the manufacturing specifications, the Permittee shall inspect the control equipment components. The Permittee shall maintain a written record of these inspections.	Minn. R. 7007.0800, subp. 4, 5 and 14
The Permittee shall operate and maintain the fabric filter in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff.	Minn. R. 7007.0800, subp. 14
PERFORMANCE TESTING	hdr
Initial Performance Test: due 180 days after Initial Startup of the wood fired boiler. Testing shall be performed for PM10 from one of the material handling baghouses with the highest calculated input grain loading.	Title I Condition: compliance with PM10 BACT limit

TABLE A: LIMITS AND OTHER REQUIREMENTS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **GP 004 Wood Boiler Continuous Monitors**

Associated Items: MR 011

MR 013

MR 014

What to do	Why to do it
Installation Notification: due 60 days before installing the continuous emissions monitoring system. The notification shall include plans and drawings of the system.	Minn. R. 7017.1040, subp. 1
All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.	40 CFR 60.13(b)
CEM Certification Test: due 60 days after achieving maximum capacity but no later than 180 days after initial startup.	40 CFR Section 40 CFR Section 60.8(a); 40 CFR Section 60.13(b); Minn. R. 7017.1050, subp. 1
CEMS Certification Test Plan: due 30 days before CEMS Certification Test.	40 CFR Section 60.7(a)(5); Minn. R. 7017.1060, subp. 1 & 2
CEMS Certification Test Pretest Meeting: due 7 days before CEMS Certification Test.	Minn. R. 7017.1060, subp. 3
CEMS Certification Test Report: due 45 days after CEMS Certification Test	Minn. R. 7017.1080, subp. 1, 2, & 4; 40CFR 60.13(c)(2)
CEMS Certification Test Report - Microfiche or CD Copy: due 105 days after CEMS Certification Test.	Minn. R. 7017.1080, subp. 3
Continuous Operation: CEMS must be operated and data recorded during all periods of emission unit operation including periods of emission unit start-up, shutdown, or malfunction except for periods of acceptable monitor downtime. This requirement applies whether or not a numerical emission limit applies during these periods. A CEMS must not be bypassed except in emergencies where failure to bypass would endanger human health, safety, or plant equipment.	40 CFR Section 60.13(e), Minn. R. 7017.1090, subp. 1
QA Plan: Develop and implement a written quality assurance plan that covers each CEMS. The plan shall be on site and available for inspection within 30 days after monitor certification. The plan shall contain all of the information required by 40 CFR pt. 60, Appendix F, Section 3.	Minn. R. 7017.1170, subp. 2; 40 CFR pt. 60, App. F; section 3
CEMS QA/QC: The owner or operator of an affected facility is subject to the performance specifications listed in 40 CFR pt. 60, Appendix B and shall operate, calibrate, and maintain each CEMS according to the QA/QC procedures in 40 CFR pt. 60, Appendix F as amended and maintain a written QA/QC program available in a form suitable for inspection.	40 CFR pt. 60, Appendix F; 40 CFR Section 60.13(a)
CEMS Daily Calibration Drift Check: Permittees must automatically check the zero (low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily. The zero and span must, at a minimum, be adjusted whenever the drift exceeds two times the limit specified in 40 CFR pt. 60, Appendix B. 40 CFR pt. 60, Appendix F shall be used to determine out-of-control periods for CEMS.	40 CFR pt. 60, Appendix F, section 4.1; 40 CFR Section 60.13(d)(1) regarding CEMS; Minn. R. 7017.1170, subp. 3
CEMS Relative Accuracy Test Audit (RATA): due before end of each calendar year following CEMS Certification Test. Follow the procedures in 40 CFR pt. 60, Appendix F.	40 CFR pt. 60, Appendix F, section 5.1.1; Minn. R. 7017.1170, subp. 5
Cylinder Gas Audit (CGA): due before end of each calendar quarter following CEMS certification test. A CGA is not required during any calendar quarter in which a RATA was performed.	40 CFR pt. 60, Appendix F, section 5.1.2; Minn. R. 7017.1170, subp. 4
Cylinder Gas Audit (CGA) Results Summary: due 30 days after end of each calendar quarter following Cylinder Gas Audit (CGA).	Minn. R. 7017.1180, subp.1
Relative Accuracy Test Audit (RATA) Notification: due 30 days before CEMS Relative Accuracy Test Audit (RATA))	Minn. R. 7017.1180, subp. 2
CEMS Relative Accuracy Test Audit (RATA): due before end of each calendar year following CEMS Certification Test. Follow the procedures in 40 CFR pt. 60, Appendix F.	40 CFR pt. 60, Appendix F, section 5.1.1; Minn. R. 7017.1170, subp. 5
Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calender quarter in which the CEMS RATA was conducted.	Minn. R. 7017.1180, subp. 3
Recordkeeping: The owner or operator must retain records of all CEMS monitoring data and support information for a period of five years from the date of the monitoring sample, measurement or report. Records shall be kept at the source.	Minn. R. 7017.1130; 40 CFR Section 60.7(f)
Monitoring Data: Reduce all data to 1-hour averages, in accordance with 40 CFR Section 60.13(h). 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period.	40 CFR Section 60.13(h) regarding continuous monitoring systems other than COMS.

TABLE A: LIMITS AND OTHER REQUIREMENTS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **GP 005 Boilers 7 and 9 Continuous Monitors**

Associated Items: MR 001

MR 002

MR 003

MR 004

MR 006

MR 008

What to do	Why to do it
SULFUR DIOXIDE CONTINUOUS MONITORING SYSTEM	hdr
CEMS Daily Calibration Drift (CD) Test: The CD shall be quantified and recorded at zero (low-level) and upscale (high-level) gas concentrations at least once daily. The CEMS shall be adjusted whenever the CD exceeds twice the specification of 40 CFR pt. 60, Appendix B. 40 CFR pt. 60, Appendix F, shall be used to determine out-of-control periods for CEMS. Follow the procedures in 40 CFR pt. 60, Appendix F.	Minn. R. 7017.1170, subp. 3
Cylinder Gas Audit (CGA): due before end of each calendar half-year following CEMS Certification Test. Conduct CGA at least 3 months apart and not greater than 8 months apart. Follow the procedures in 40 CFR pt. 60, Appendix F.	Minn. R. 7017.1170, subp. 4
Cylinder Gas Audit (CGA) Results Summary: due 30 days after end of each calendar half-year following Cylinder Gas Audit (CGA)	Minn. R. 7017.1180, subp. 1
CEMS Relative Accuracy Test Audit (RATA): due before end of each calendar year following CEMS Certification Test. If the relative accuracy is 15% or less the next CEMS RATA is not due for 24 months. Follow the procedures in 40 CFR pt. 60, Appendix B and Appendix F.	Minn. R. 7017.1170, subp. 5
Relative Accuracy Test Audit (RATA) Notification: due 30 days before CEMS Relative Accuracy Test Audit (RATA).	Minn. R. 7017.1180, subp. 2
Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calender quarter in which the CEMS RATA was conducted.	Minn. R. 7017.1180, subp. 3
Continuous Operation: CEMS must be operated and data recorded during all periods of emission unit operation including periods of emission unit start-up, shutdown, or malfunction except for periods of acceptable monitor downtime. This requirement applies whether or not a numerical emission limit applies during these periods. A CEMS must not be bypassed except in emergencies where failure to bypass would endanger human health, safety, or plant equipment. Acceptable monitor downtime includes reasonable periods as listed in Items A, B, C and D of Minn. R. 7017.1090, subp. 2.	Minn. R. 7017.1090, subp. 1
Recordkeeping: The owner or operator must retain records of all CEMS monitoring data and support information for a period of five years from the date of the monitoring sample, measurement or report. Records shall be kept at the source.	Minn. R. 7007.1130
OPACITY CONTINOUS MONITORS	hdr
Continuous Operation: COMS must be operated and data recorded during all periods of emission unit operation including periods of emission unit start-up, shutdown, or malfunction except for periods of acceptable monitor downtime. This requirement applies whether or not a numerical emission limit applies during these periods. A COMS must not be bypassed except in emergencies where failure to bypass would endanger human health, safety, or plant equipment. Acceptable monitor downtime includes reasonable periods as listed in Items A, B, C and D of Minn. R. 7017.1090, subp. 2.	Minn. R. 7017.1090, subp. 1; 40 CFR Section 60.13(e)
COMS QA/QC: The owner or operator of an affected facility is subject to the performance specifications listed in 40 CFR pt. 60, Appendix B and shall operate, calibrate, and maintain each COMS according to the QA/QC procedures in Minn. R. 7017.1210.	40 CFR Section 60.13(a); Minn. R. 7017.1210
COMS Daily Calibration Drift Check: The Permittee must automatically, intrinsic to the opacity monitor, check the zero and upscale (span) calibration drifts at least once daily. The acceptable range is as defined in 40 CFR pt. 60, Appendix B, PS-1. The span value shall be between 60% and 80%. For COMS without automatic zero adjustments the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments. For COMS with automatic zero adjustmens. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition as specified in 40 CFR 60.13(d)(2).	Minn. R. 7017.1210, subp. 2; 40 CFR Section 60.13(d)(l) regarding COMS and 60.13(d)(2)

COMS Calibration Error Audit: due before end of each calendar half-year following COMS Certification Test. Conduct three point calibration error audits at least 3 months apart but no greater than 8 months apart. Conduct audits in accordance with Minn. R. 7017.1210, subp. 3.	Minn. R. 7017.1210, subp. 3
Attenuator Calibration: The Permittee shall perform an attenuator calibration in accordance with Minn. R. 7017.1210, subp. y.	Minn. R. 7017.1210, subp. 4
COMS Calibration Error Audit Results Summary: due 30 days after end of each calendar quarter in which the COMS calibration error audit was completed.	Minn. R. 7017.1220
Recordkeeping: The owner or operator must retain records of all COMS monitoring data and support information for a period of five years from the date of the monitoring sample, measurement or report. Records shall be kept at the source.	Minn. R. 7017.1130

TABLE A: LIMITS AND OTHER REQUIREMENTS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 001 Boiler #7**

Associated Items: CE 001 Centrifugal Collector - Medium Efficiency

CE 002 Electrostatic Precipitator - High Efficiency

GP 001 Boilers 7 and 9 SO2 limits

GP 002 Boilers 7, 9, and 10 and makeup air heater

MR 001

MR 002

MR 006

SV 002 Boiler No. 7

What to do	Why to do it
EMISSION AND FUEL TYPE LIMITS See GP001 table for sulfur dioxide emission limits.	hdr
Total Particulate Matter: less than or equal to 0.6 lbs/million Btu heat input	Minn. R. 7011.0510, subp. 1
Particulate Matter < 10 micron: less than or equal to 0.3 lbs/million Btu heat input	Title I Condition: 40 CFR 52.21(k) Ambient Impacts Analysis
Opacity: less than or equal to 20 percent opacity except for one six-minute period per hour of not more than 60 percent opacity. An exceedance of this opacity standard occurs whenever any one-hour period contains two or more six-minute periods during which the average opacity exceeds 20 percent or whenever any one-hour period contains one or more six-minute periods during which the average opacity exceeds 60 percent.	40 CFR Part 64, also meets the requirements of Minn. R. 7011.0510, subp. 2
Fuels Allowed: natural gas, subbituminous coal, and bituminous coal.	Minn. R. 7007.0800, subp. 2
RECORDKEEPING	hdr
Fuel Usage Recordkeeping: by the 15th day of each month, the Permittee shall record the EU 001 fuel usage (for each permitted fuel) for the previous calendar month. The monthly values shall be used in the NOx emisisons calculation equation (Equation 1) in the total facility section of this permit.	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR Section 52.21; Minn. R. 7007.0800, subp. 5
PERFORMANCE TESTING	hdr
Performance Test: due before end of each 60 months starting 09/23/2004 to measure particulate matter emissions while burning coal. The particulate matter emissions tests shall be conducted at an interval not to exceed 60 months between test dates.	Minn. R. 7017.2020, subp. 1
Performance Test: due 180 days after Permit Issuance for PM10 emissions.	Title I Condition: to determine compliance with PM10 limit
Performance Test: due before end of each 24 months starting 09/23/2004 to measure NOx emissions while burning coal, and while burning natural gas. The NOx tests are for the purpose of determining the NOx emission factor (EF1) for use in Equation 1 in the GP002 section of the permit.	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR 52.21
Performance Test Notifications and Submittals: Performance Tests are due as outlined in Tables A and B of the permit. See Table B for additional testing requirements. Performance Test Notification (written): due 30 days before each Performance Test Performance Test Plan: due 30 days before each Performance Test Performance Test Pre-test Meeting: due 7 days before each Performance Test Performance Test Report: due 45 days after each Performance Test Performance Test Report - Microfiche Copy: due 105 days after each Performance Test	Minn. R. 7017.2030, subp. 1-4 and Minn. R. 7017.2035, subp. 1-2
Boiler Alternative Operating Conditions for Performance Testing: Alternative Operating Conditions during testing are defined as 90% to 100% of the boiler's maximum normal (continuous) operating load or the maximum permitted operating rate, whichever is lower. The basis for this number must be included in the test plan. If testing is conducted at the alternative operating condition established, an operating limit will not be established as a result of performance testing. In no case will the new operating rate limit be higher than allowed by an existing permit condition.	Minn. R. 7017.2025, subp. 2(A) and 3(B)

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Boiler Operating Conditions Not Meeting the Alternative Operating Conditions During Performance Testing: If performance testing in not conducted at or above the established alternative operating condition, then the boiler operating rate will be limited on an 8-hour block average based on the following: (1) If the results of the performance test are greater than 80% of any applicable emission limit for which compliance is demonstrated, then boiler operation will be limited to the tested operating rate. (2) If results are less than or equal to 80% of all applicable emission limits for which compliance is demonstrated, boiler operation will be limited to 110% of the tested operating rate. In no case will the new operating rate limit be higher than allowed by an existing permit condition.	Minn. R. 7017.2025, subp. 3(B)
STET (Short Term Emergency and Testing) Operating hours limit: The boiler may operate up to 40 hours per year to demonstrate the Uniform Rating of Generating Equipment (URGE) capacity and to meet emergency energy supply needs. Maintain documentation of all STET operation to demonstrate compliance with this limit. The boiler must meet emission limits during STET operation.	Minn. R. 7007.0800, subp. 2
STET Operation Definition that applies to Boilers that Meet or do Not Meet the Alternative Operating Condition for Performance Testing: If performance test results demonstrate compliance at 80% or less of any applicable emission limits for any tested pollutant, STET operation is defined as operation beyond 110% of the average operating rate achieved during that performance test. If performance test results demonstrate compliance at greater than 80% of any applicable emission limit for any tested pollutant, STET operation is defined as operation beyond 100% of the average operating rate achieved during that performance test. In no case will STET operation be higher than allowed by an existing permit condition.	Minn. R. 7007.0800, subp. 2
The results of a performance test are not final until issuance of a review letter by MPCA, unless specified otherwise by Minn. R. 7017.2001-7017.2060.	Minn. R. 7017.2020, subp. 4
CONTINUOUS MONITORING REQUIREMENTS	hdr
Emission Monitoring: The Permittee shall use a COMS on SV 002 to measure opacity emissions from EU 001, upon commencing coal combustion.	Minn. R. 7007.0800, subp. 2
Emissions Monitoring: The Permittee shall use a SO2 CEMS on SV 002 to measure SO2 emissions from EU 001, upon commencing coal combustion.	Minn. R. 7007.0800, subp. 2
CONTROL EQUIPMENT OPERATING PARAMETERS	hdr
Collect the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to 40 CFR Section 63.7525.	40 CFR Part 64
Reduce the data to 3-hour block averages; and Maintain the 3-hour average secondary current and voltage or total power input at or above the level established during the most recent performance test that demonstrated compliance with the particulate matter and PM10 emission limits.	continued from above

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 003 Boiler #9**

Associated Items: CE 003 Electrostatic Precipitator - High Efficiency

GP 001 Boilers 7 and 9 SO2 limits

GP 002 Boilers 7, 9, and 10 and makeup air heater

MR 003

MR 004

MR 008

SV 003 Boiler No. 9

What to do	Why to do it
EMISSION AND FUEL LIMITS	hdr
Total Particulate Matter: less than or equal to 0.6 lbs/million Btu heat input	Minn. R. 7011.0510, subp. 1
Particulate Matter < 10 micron: less than or equal to 0.3 lbs/million Btu heat input	Title I Condition: 40 CFR 52.21(k) Ambient Impacts Analysis
Opacity: less than or equal to 20 percent opacity except for one six-minute period per hour of not more than 60 percent opacity. An exceedance of this opacity standard occurs whenever any one-hour period contains two or more six-minute periods during which the average opacity exceeds 20 percent or whenever any one-hour period contains one or more six-minute periods during which the average opacity exceeds 60 percent.	40 CFR Part 64, also meets the requirements of Minn. R. 7011.0510, subp. 2
Fuels Allowed: subbituminous coal, bituminous coal, and oily cellulose-based sorbents (including oily rags).	Minn. R. 7007.0800, subp. 2
Fuel Usage Limit: The Permittee shall not combust more than 500 pounds per year of oily cellulose-based sorbents (oily rags) in EU 003.	Minn. R. 7007.0800, subp. 2
RECORDKEEPING	hdr
Fuel Usage Recordkeeping: by the 15th day of each month the Permittee shall record the type and quantity of fuels burned in EU 003 during the previous month. The monthly records shall be used in the NOx emission calculation equation (Equation 1) in the total facility section of this permit.	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR Section 52.21; Minn. R. 7007.0800, subp. 5
PERFORMANCE TESTING REQUIREMENTS	hdr
Performance Test: due 180 days after Permit Issuance for PM10 emissions.	Title I Condition: to determine compliance with PM10 limit
Performance Test: due before end of each 60 months starting 01/31/2003 to measure particulate matter emissions. The particulate matter emissions tests shall be conducted at an interval not to exceed 60 months between test dates.	Minn. R. 7017.2020, subp. 1
Performance Test: due before end of each 24 months starting 09/23/2004 to measure NOx emissions while burning coal. The NOx tests are for the purpose of determining the NOx emission factor (EF3) for use in Equation 1 in the GP002 section of the permit.	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR 52.21
Performance Test Notifications and Submittals: Performance Tests are due as outlined in Tables A and B of the permit. See Table B for additional testing requirements. Performance Test Notification (written): due 30 days before each Performance Test Performance Test Plan: due 30 days before each Performance Test Performance Test Pre-test Meeting: due 7 days before each Performance Test Performance Test Report: due 45 days after each Performance Test Performance Test Report - Microfiche Copy: due 105 days after each Performance Test	Minn. R. 7017.2030, subp. 1-4 and Minn. R. 7017.2035, subp. 1-2
Boiler Alternative Operating Conditions for Performance Testing: Alternative Operating Conditions during testing are defined as 90% to 100% of the boiler's maximum normal (continuous) operating load or the maximum permitted operating rate, whichever is lower. The basis for this number must be included in the test plan. If testing is conducted at the alternative operating condition established, an operating limit will not be established as a result of performance testing. In no case will the new operating rate limit be higher than allowed by an existing permit condition.	Minn. R. 7017.2025, subp. 2(A) and 3(B)

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Boiler Operating Conditions Not Meeting the Alternative Operating Conditions During Performance Testing: If performance testing in not conducted at or above the established alternative operating condition, then the boiler operating rate will be limited on an 8-hour block average based on the following: (1) If the results of the performance test are greater than 80% of any applicable emission limit for which compliance is demonstrated, then boiler operation will be limited to the tested operating rate. (2) If results are less than or equal to 80% of all applicable emission limits for which compliance is demonstrated, boiler operation will be limited to 110% of the tested operating rate. In no case will the new operating rate limit be higher than allowed by an existing permit condition.	Minn. R. 7017.2025, subp. 3(B)
STET (Short Term Emergency and Testing) Operating hours limit: The boiler may operate up to 40 hours per year to demonstrate the Uniform Rating of Generating Equipment (URGE) capacity and to meet emergency energy supply needs. Maintain documentation of all STET operation to demonstrate compliance with this limit. The boiler must meet emission limits during STET operation.	Minn. R. 7007.0800, subp. 2
STET Operation Definition that applies to Boilers that Meet or do Not Meet the Alternative Operating Condition for Performance Testing: If performance test results demonstrate compliance at 80% or less of any applicable emission limits for any tested pollutant, STET operation is defined as operation beyond 110% of the average operating rate achieved during that performance test. If performance test results demonstrate compliance at greater than 80% of any applicable emission limit for any tested pollutant, STET operation is defined as operation beyond 100% of the average operating rate achieved during that performance test. In no case will STET operation be higher than allowed by an existing permit condition.	Minn. R. 7007.0800, subp. 2
The results of a performance test are not final until issuance of a review letter by MPCA, unless specified otherwise by Minn. R. 7017.2001-7017.2060.	Minn. R. 7017.2020, subp. 4
CONTINUOUS MONITORING REQUIREMENTS	hdr
Emission Monitoring: The Permittee shall use a COMS to measure opacity emissions from EU 003.	Minn. R. 7007.0800, subp. 2
Emissions Monitoring: The Permittee shall use a SO2 CEMS to measure SO2 emissions from EU 003.	Minn. R. 7007.0800, subp. 2
CONTROL EQUIPMENT OPERATING PARAMETERS	hdr
Collect the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to 40 CFR Section 63.7525.	40 CFR Part 64
Reduce the data to 3-hour block averages; and Maintain the 3-hour average secondary current and voltage or total power input at or above the level established during the most recent performance test that demonstrated compliance with the particulate matter and PM10 emission limits.	continued from above

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 004 Boiler #10**

Associated Items: CE 004 Modified Furnace or Burner Design

CE 005 Flue Gas Recirculation

CE 006 Low Excess - Air Firing

GP 002 Boilers 7, 9, and 10 and makeup air heater

MR 005

MR 010

SV 004 Natural Gas Boiler 10

What to do	Why to do it
EMISSION AND FUEL TYPE LIMITS	hdr
Total Particulate Matter: less than or equal to 0.03 lbs/million Btu heat input	40 CFR Section 60.42a(a)(1)
Opacity: less than or equal to 20 percent opacity using 6 Minute Average except for one 6-minute period per hour of not more than 27 percent opacity.	40 CFR Section 60.42a(b)
Sulfur Dioxide: less than or equal to 0.20 lbs/million Btu heat input using 30-day Rolling Average	40 CFR Section 60.43a(b)(2)
Nitrogen Oxides: less than or equal to 0.10 lbs/million Btu heat input using 30-day Rolling Average	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR Section 52.21; meets requirements of 40 CFR Section 60.44a(a)(1)
Fuels Allowed: EU 004 fuel is restricted to natural gas only.	Minn. R. 7007.0800, subp 2
CONTINUOUS EMISSIONS MONITORING	hdr
Emissions Monitoring: The Permittee shall use a NOx CEMS to measure NOx emissions from EU 004, and record the output of the system.	Title I Condition: to limit NOx emissions increase to less than the significant level in 40 CFR Section 52.21; ensures compliance with 40 CFR Section 60.47a(c)
Emissions Monitoring: The owner or operator shall operate and maintain a CO2 or O2 CEMS at the location of the NOx CEMS, and record the output of the system.	40 CFR Section 60.47a(d)
CEMS Continuous Operation: Except for system breakdowns, repairs, calibration checks and zero and span adjustments, all CEMS shall be in continuous operation while the boiler is operating (combusting fuel).	40 CFR Section 60.47a(e); 40 CFR Section 60.13(e)
CEMS Daily Calibration Drift (CD) Test: The CD shall be quantified and recorded at zero (low-level) and upscale (high-level) gas concentrations at least once daily. The CEMS shall be adjusted whenever the CD exceeds twice the specification of 40 CFR pt. 60, Appendix B. 40 CFR pt. 60, Appendix F, shall be used to determine out-of-control periods for CEMS.	40 CFR Section 60.48a(d); 40 CFR pt. 60, Appendix F, section 4.1; 40 CFR Section 60.13(d)(1)
CEMS Cylinder Gas Audit (CGA): due before end of each calendar half-year following CEM Certification Test. Conduct CGA at least 3 months apart and not greater than 8 months apart. Follow the procedures in 40 CFR pt. 60, Appendix F.	40 CFR Section 60.48a(d); 40 CFR pt. 60, Appendix F, section 5.1.2
Cylinder Gas Audit (CGA) Results Summary: due 30 days after end of each calendar quarter following Cylinder Gas Audit (CGA).	40 CFR Section 60.48a(d); 40 CFR pt. 60, Appendix F, section 1
CEMS Relative Accuracy Test Audit (RATA): due before end of each calendar year starting 12/22/1998 . If the relative accuracy is 15% or less the next CEMS RATA is not due for 24 months. Follow the procedures in 40 CFR pt. 60, Appendix B and Appendix F.	40 CFR Section 60.48a(d); 40 CFR pt. 60, Appendix F, section 5.1.1
Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calender quarter in which the CEMS RATA was conducted.	40 CFR Section 60.48a(d); 40 CFR pt. 60, Appendix F, section 1
RECORDKEEPING	hdr
Recordkeeping: The owner or operator must retain records of all CEMS/COMS monitoring data and support information for a period of five (5) years from the date of the monitoring sample, measurement or report. Records shall be kept at the source.	40 CFR Section 60.7(f); Minn. R. 7007.0800, subp. 5

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 006 Wood Fired Boiler**

Associated Items: CE 007 Multiple Cyclone w/o Fly Ash Reinjection - Most Multiclones

CE 008 Selective Noncatalytic Reduction for NOX

CE 009 Electrostatic Precipitator - High Efficiency

MR 011

MR 012

MR 013

MR 014

SV 005 Wood Fired Boiler

What to do	Why to do it
EMISSION LIMITS	hdr
Total Particulate Matter: less than or equal to 0.025 lbs/million Btu heat input . This limit applies at all times, except during periods of startup, shutdown or malfunction.	Title I Condition: BACT limit; 40 CFR 52.21(j), also meets the requirements of 40 CFR Section 63.7500 and 40 CFR Section 60.43b(c)(1)
Particulate Matter < 10 micron: less than or equal to 0.025 lbs/million Btu heat input . This limit applies at all times except during periods of startup, shutdown or malfunction.	Title I Condition: BACT limit; 40 CFR 52.21(j)
Carbon Monoxide: less than or equal to 0.3 lbs/million Btu heat input based on a 4-hour block average. "Four-hour block average" means the average of all hourly emission rates when the emissions unit is operating over six discrete four-hour periods beginning at midnight. This limit applies at all times, except during periods of startup, shutdown, or malfunction.	Title I Condition: BACT limit; 40 CFR 52.21(j), also meets the requirements of 40 CFR Section 63.7500
Hydrochloric acid: less than or equal to 0.02 lbs/million Btu heat input . This limit applies at all times, except during periods of startup, shutdown or malfunction.	40 CFR Section 63.7500
Nitrogen Oxides: less than or equal to 0.15 lbs/million Btu heat input based on a 30-day rolling average.	Title I Condition: BACT limit; 40 CFR 52.21(j)
Mercury: less than or equal to 0.000003 lbs/million Btu heat input . This limit applies at all times, except during periods of startup, shutdown or malfunction.	40 CFR Section 63.7500
Opacity: less than or equal to 10 percent based on a 1-hour block average.	40 CFR Section 63.7500
Opacity: less than or equal to 20 percent based on a 6-minute average, except for one 6-minute period per hour of not more than 27 percent opacity. This limit applies at all times, except during periods of startup, shutdown or malfunction.	40 CFR Section 60.43b(f)
Ammonia Slip: Limited to less than or equal to 25 ppm. If the ammonia slip exceeds this level, the SNCR system shall be adjusted to reduce the ammonia slip to less than 25 ppm, or shut down until repairs are made and normal operating conditions are achieved.	Minn. R. 7007.0800, subp. 2
OPERATING LIMITS	hdr
Fuel use limited to untreated wood, such as, but not limited to, logging waste, trees, brush, etc. Untreated wood is defined as any wood that has not been subject to any chemical treatment or coating. Examples are: 1) untreated residuals from manufacturing processes such as furniture, cabinet, and pallet making and other wood product manufacture; 2) construction waste; 3) urban and park tree trimming and forest residuals; 4) wood from trees downed by storms; 5) trees removed for urban development; 6) trees grown specifically to be used as fuel; and 7) trees removed as part of a timber management plan.	Minn. R. 7007.0800, subp. 2
The SNCR system will be adjusted or may be shut down when the ammonia slip exceeds the limit set above, until such time as the system is returned to normal operation.	Minn. R. 7007.0800, subp. 2

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

At all times, including periods of startup, shutdown, and malfunction, owners or operators shall operate and maintain any affected source, including the associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions at least to the levels required by all relevant standards. Malfunctions shall be corrected as soon as practicable after their occurence in accordance with the startup, shutdown, and malfunction plan required below and by 40 CFR Section 63.6(e)(3).	40 CFR Section 63.6(e)(1)(i) and 40 CFR Section 60.11(d)
Fuel use is limited in chlorine content to the maximum that was burned during the compliance test that demonstrated compliance with the HCl emission limit. Procedures for determining the maximum chlorine content are specified at 40 CFR Section 63.7530(c)(1)(i)-(iii).	40 CFR Section 63.7530(c)(1)
Fuel use is limited in mercury content to the maximum that was burned during the compliance test that demonstrated compliance with the mercury emission limit. Procedures for determining the maximum mercury content are specified at 40 CFR Section 63.7530(c)(3)(i)-(iii).	40 CFR Section 63.7530(c)(3)
INITIAL COMPLIANCE DEMONSTRATION	hdr
Performance Test: due 60 days after achieving maximum capacity but no later than 180 days after initial startup for particulate matter, PM10, and opacity. You must establish the minimum voltage and secondary current (or total power input) as defined in 40 CFR Section 63.7575 for the electrostatic precipitator.	40 CFR Section 63.7510(a), 40 CFR Section 60.11(e), Title I Condition, compliance with PM10 BACT limits
Determine compliance with the emission limits for hydrogen chloride and mercury through fuel analysis within 180 days of initial startup. Follow the procedures specified in 40 CFR Section 63.7521 and Table 6 to Subp. DDDDD.	40 CFR Section 63.7530(d)
CONTINUOUS MONITORING REQUIREMENTS	hdr
Install, maintain and operate a monitor to measure stack carbon monoxide emissions. The monitor shall meet the requirements of 40 CFR 63.7525(a). For more specific requirements, see the GP004 table in this permit.	40 CFR Section 63.7525(a)
Install, maintain, and operate a continuous monitor to measure the opacity of stack emissions. The monitor shall meet the requirements of 40 CFR 63.7525(b). For more specific requirements, see the MR012 table in this permit.	40 CFR Section 63.7525(b) 40 CFR Section 60.48b(a)
Install, operate and maintain a continuous monitor to measure stack nitrogen oxides emissions. Installation, operation and maintenance shall be in accordance with 40 CFR Section 60.15 and 40 CFR 60, Appendix B. For more specific requirements, see the GP004 table in this permit.	Title I Condition: Monitoring of BACT limit 40 CFR Section 64.3(d)(2)
OPERATING CONDITIONS FOR CONTROL EQUIPMENT	hdr
At all times, including periods of startup, shutdown, and malfunction, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires you to reduce emissions from the affected source to the greatest extent which is consistent with safety and good air pollution control practices.	40 CFR Section 63.7505(b), 40 CFR Section 63.6(e)(1)(i)
The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require you to achieve emission levels that would be required by the applilcable standard at other times if this is not consistent with safety and good air pollution control practices, nor does it require you to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures (including the startup, shutdown and malfunction plan required by 40 CFR Section 63.6(e)), review of operation and maintenance records, and inspection of the source.	continued from above
Collect the secondary current and Voltage or total power input monitoring system data for the electrostatic precipitator according to 40 CFR Section 63.7525 and 63.7535; and reduce the data to 3-hour block averages; and maintain the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance testaccording to 40 CFR Section 63.7530(c).	40 CFR Section 63.7530, 40 CFR Section 63.7540(a)
SUBMITTALS AND REPORTING	hdr
RECORDKEEPING	hdr

Keep all records readily available and on site for a period of 5 years. Maintain relevant records of each startup, shutdown, or malfuncation of operation equipment and the occurrence and duration of each malfunction of the required air pollution control and monitoring equipment.	40 CFR Section 60.7(b), 40 CFR Section 63.10(b)(1)
Maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these sytems or devices; and all other information required by this part recorded in a permanent form suitable for inspection.	40 CFR Section 60.7(f)
Keep records of the type and amount of all fuels burned to demonstrate that all fuel types and mixtures of fuels burned would result in lower emissions of HCl and mercury than the applicable emission limit. If you plan to burn a new type of fuel, you must recalculate the HCl emission rate using Equation 9 of 40 CFR Section 63.7530 and 40 CFR Section 63.7540(a)(3). You must also recalculate the mercury emission rate according to 40 CFR Section 7540(a)(7) and Equation 11 of 40 CFR Section 63.7530.	40 CFR Section 63.7540(a)(2)
Keep records of carbon monoxide levels according to 40 CFR Section 63.7555(b).	40 CFR Section 63.7540(a)(10)
Full recordkeeping requirements are specified in 40 CFR Section 63.7555 and include copies of all notifications, reports, tests, fuel analyses, compliance demonstrations, performance demonstrations, CEM and COMs data, deviations, fuel use, and all calculations that demonstrate compliance with emission limits.	40 CFR Section 63.7555
STARTUP, SHUTDOWN AND MALFUNCTION PLAN	hdr
Startup, shutdown, and malfunction plan. (i) Develop and implement a written startup, shutdown, and malfunction plan that describes in detail, procedures for operating and maintaining the source during periods of startup, shutdown and malfunction, and a program of corrective action for malfunctioning process and air pollution control and monitoring equipment used to comply with the relevant standard. This plan must be developed by the compliance date (upon startup). The purpose of the startup, shutdown, and malfunction plan is to:	40 CFR Section 63.6(e)(3)(i)
(A) Ensure that, at all times, that you operate and maintain the source, including associated air pollution control and monitoring equipment, in a manner which satisfies the general duty to minimize emissions established by 40 CFR Section 63.6(e)(1)(i); (B) Ensure that you are prepared to correct malfunctions as soon as practicable after their occurrence in order to minimize excess emissions of hazardous air pollutants; and (C) Reduce the reporting burden associated with periods of startup, shutdown and malfunction (including corrective actio taken to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation.	continued from above
During periods of startup, shutdown, and malfunction, you must operate and maintain the source (including associated air pollution control and monitoring equipment) in accordance with the procedures specified in the startup, shutdown, and malfunction plan developed under 40 CFR Section 63.6(e)(3)(i).	40 CFR Section 63.6(e)(3)(ii)
When actions taken by you during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) are consistent with the procedures specified in the sources's startup, shutdown and malfunction plan, you must keep records for that event which demonstrate that the procedures specified in the plan were followed. These records may take the form of a checklist, or other effective form of recordkeeping that confirms conformance with the startup, shutdown and malfunction plan for that event.	40 CFR Section 63.6(e)(3)(iii)
In addition, you must keep records of these events as specified in 40 CFR Section 63.10(b), including records of the occurrence and duration of each startup, shutdown, or malfunction of operation and each malfunction of the air pollution control and monitoring equipment. Furthermore, the owner or operator shall confirm that actions taken during the relevant reporting period during periods of startup, shutdown, and malfunction were consistent with the affected source's startup, shutdown and malfunction plan in the semiannual startup, shutdown, and malfunction report required in 40 CFR Section 63.10(d)(5).	continued from above
If you take an action during a startup, shutdown, or malfunction (including an action taken to correct a malfunction) that is not consistent with the procedures specified in the affected source's startup, shutdown and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard, then the owner or operator must record the actions taken for that event and must report such actions within 2 working days after commencing actions inconsistent with the plan, followed by a letter within 7 working days after the end of the event, in accordance with Section 63.10(d)(5) (unless the owner or operator makes alternative reporting arrangements, in advance, with the Administrator.)	40 CFR Section 63.6(e)(3)(iv)

You must maintain at the affected source a current startup, shutdown, and malfunction plan and must make the plan available upon request for inspection and copying by the Administrator. In addition, if the startup, shutdown and malfunction plan is subsequently revised as provided in paragraph (e)(3)(viii) of this section, the you must maintain at the affected source each previous (i.e., superseded) version of the startup, shutdown, and malfunction plan, and must make each such previous version available for inspection and copying by the Administrator for a period of 5 years after revision of the plan.	40 CFR Section 63.6(e)(3)(v)
If at any time after adoption of a startup, shutdown, and malfunction plan the affected source ceases operation or is otherwise no longer subject to the provisions of this part, you must retain a copy of the most recent plan for 5 years from the date the source ceases operation or is no longer subject to this part and must make the plan available upon request for inspection and copying by the Administrator. The Administrator may at any time request in writing that you submit a copy of any startup, shutdown, and malfunction plan (or a portion thereof) which is maintained at the affected source or in the possession of the owner or operator.	continued from above
Upon receipt of such a request, you must promptly submit a copy of the requested plan (or a portion thereof) to the Administrator. The Administrator must request that the you submit a particular startup, shutdown, or malfunction plan (or a portion thereof) whenever a member of the public submits a specific and reasonable request to examine or to receive a copy of that plan or portion of a plan. You may elect to submit the required copy of any startup, shutdown, and malfunction plan to the Administrator in an electronic format. If the owner or operator claims that any portion of such a startup, shutdown, and malfunction plan is confidential business information entitled to protection from disclosure under section 114(c) of the Act or 40 CFR 2.301, the material which is claimed as confidential must be clearly designated in the submission.	continued from above
To satisfy the requirements of this section to develop a startup, shutdown, and malfunction plan, you may use the affected source's standard operating procedures (SOP) manual, or an Occupational Safety and Health Administration (OSHA) or other plan, provided the alternative plans meet all the requirements of this section and are made available for inspection or submitted when requested by the Administrator.	40 CFR Section 63.6(e)(3)(vi)
Based on the results of a determination made under paragraph (e)(1)(i) of this section, the Administrator may require that you make changes to the startup, shutdown, and malfunction plan for that source. The Administrator must require appropriate revisions to a startup, shutdown, and malfunction plan, if the Administrator finds that the plan: (A) Does not address a startup, shutdown, or malfunction event that has occurred; (B) Fails to provide for the operation of the source (including associated air pollution control and monitoring equipment) during a startup, shutdown, or malfunction event in a manner consistent with the general duty to minimize emissions established by paragraph (e)(1)(i) of this section;	40 CFR Section 63.6(e)(3)(vii)
(C) Does not provide adequate procedures for correcting malfunctioning process and/or air pollution control and monitoring equipment as quickly as practicable; or (D) Includes an event that does not meet the definition of startup, shutdown, or malfunction listed in Section 63.2.	continued from above
You may periodically revise the startup, shutdown, and malfunction plan for the affected source as necessary to satisfy the requirements of this part or to reflect changes in equipment or procedures at the affected source. Unless the permitting authority provides otherwise, you may make such revisions to the startup, shutdown, and malfunction plan without prior approval by the Administrator or the permitting authority. However, each such revision to a startup, shutdown, and malfunction plan must be reported in the semiannual report required by Section 63.10(d)(5).	40 CFR Section 63.6(e)(3)(viii)
If the startup, shutdown, and malfunction plan fails to address or inadequately addresses an event that meets the characteristics of a malfunction but was not included in the startup, shutdown, and malfunction plan at the time you developed the plan, you must revise the startup, shutdown, and malfunction plan within 45 days after the event to include detailed procedures for operating and maintaining the source during similar malfunction events and a program of corrective action for similar malfunctions of process or air pollution control and monitoring equipment.	continued from above
In the event that you make any revision to the startup, shutdown, and malfunction plan which alters the scope of the activities at the source which are deemed to be a startup, shutdown, or malfunction, or otherwise modifies the applicability of any emission limit, work practice requirement, or other requirement in a standard established under this part, the revised plan shall not take effect until after the you have provided a written notice describing the revision to the permitting authority.	continued from above

The title V permit for an affected source must require that you adopt a startup, shutdown, and malfunction plan which conforms to the provisions of this part, and that you operate and maintain the source in accordance with the procedures specified in the current startup, shutdown, and malfunction plan. However, any revisions made to the startup, shutdown, and malfunction plan in accordance with the procedures established by this part shall not be deemed to constitute permit revisions under part 70 or part 71 of this chapter. Moreover, none of the procedures specified by the startup, shutdown, and malfunction plan for an affected source shall be deemed to fall within the permit shield provision in section 504(f) of the Act.	40 CFR Section 63.6(e)(3)(ix)
PERFORMANCE STACK EMISSION TESTING	hdr
All performance tests and fuel analyses used for demonstrating compliance with emission limits must be conducted on an annual basis except as provided for in 40 CFR Section 63.7515. If three consecutive tests show compliance with the emission limits, you may choose to conduct the performance tests for these pollutants every third year. If a test shows noncompliance with an emission limit you must conduct annual performance tests until all performance tests over a consecutive 3 year period show compliance.	40 CFR Section 63.7515
Performance tests and procedures under 40 CFR 63.7520 and 40 CFR Section 60.46b(d) must be followed. 40 CFR Section 63.7520 calls for: -a 60 day notice of intent to test, -development and submittal of a site specific test plan, -request and use of performance audit samples (request due 30 days prior to the test), -provision of adequate testing facilities, -testing during representative operation, -specifies that methods used be consistent with those specified in Parts 51, 60, 61, and 63. The methods are specified in Table 5 to Subp. DDDDD, and -submittal of results within 60 days of the performance test (Minn. R. requires submittal within 45 days, and will take precedence.) 40 CFR Section 60.46b(d) specifies test methods for particulate and opacity. Particulate matter test methods are the same as those specified in Table 5 to subp. DDDDD.	40 CFR Section 63.7520 40 CFR Section 60b(d) and (e)
Boiler Alternative Operating Conditions for Performance Testing: Alternative Operating Conditions during testing are defined as 90% to 100% of the boiler's maximum normal (continuous) operating load or the maximum permitted operating rate, whichever is lower. The basis for this number must be included in the test plan. If testing is conducted at the alternative operating condition established, an operating limit will not be established as a result of performance testing. In no case will the new operating rate limit be higher than allowed by an existing permit condition.	Minn. R. 7017.2025, subp. 2(A) and 3(B)
Boiler Operating Conditions Not Meeting the Alternative Operating Conditions During Performance Testing: If performance testing in not conducted at or above the established alternative operating condition, then the boiler operating rate will be limited on an 8-hour block average based on the following: (1) If the results of the performance test are greater than 80% of any applicable emission limit for which compliance is demonstrated, then boiler operation will be limited to the tested operating rate. (2) If results are less than or equal to 80% of all applicable emission limits for which compliance is demonstrated, boiler operation will be limited to 110% of the tested operating rate. In no case will the new operating rate limit be higher than allowed by an existing permit condition.	Minn. R. 7017.2025, subp. 3(B)
STET (Short Term Emergency and Testing) Operating hours limit: The boiler may operate up to 40 hours per year to demonstrate the Uniform Rating of Generating Equipment (URGE) capacity and to meet emergency energy supply needs. Maintain documentation of all STET operation to demonstrate compliance with this limit. The boiler must meet emission limits during STET operation.	Minn. R. 7007.0800, subp. 2

STET Operation Definition that applies to Boilers that Meet or do Not Meet the Alternative Operating Condition for Performance Testing: If performance test results demonstrate compliance at 80% or less of any applicable emission limits for any tested pollutant, STET operation is defined as operation beyond 110% of the average operating rate achieved during that performance test. If performance test results demonstrate compliance at greater than 80% any applicable emission limit for any tested pollutant, STET operation is defined as operation beyond 100% of the average operating rate achieved during that performance test. In no case will STET operation be higher than allowed by an existing permit condition.	Minn. R. 7007.0800, subp. 2
CONTROL EQUIPMENT OPERATING PARAMETERS	hdr
Collect the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to 40 CFR Section 63.7525.	40 CFR Section 63.7540 and Table 8 to Subp. DDDDD
Reduce the data to 3-hour block averages; and Maintain the 3-hour average secondary current and voltage or total power input at or above the level established during the most recent performance test that demonstrated compliance with the particulate matter and PM10 emission limits.	continued from above

TABLE A: LIMITS AND OTHER REQUIREMENTS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 007 Enclosed Wood Unloading**

Associated Items: CE 010 Fabric Filter - Low Temperature, i.e., T<180 Degrees F

SV 006 Enclosed Wood Unloading Area

What to do	Why to do it
Particulate Matter < 10 micron: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Total Particulate Matter: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Opacity: less than or equal to 20 percent	Minn. R. 7011.0715
For compliance demonstration, see GP003 requirements table.	hdr

TABLE A: LIMITS AND OTHER REQUIREMENTS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 008 Wood Storage Silo**

Associated Items: CE 011 Fabric Filter - Low Temperature, i.e., T<180 Degrees F

CE 012 Fabric Filter - Low Temperature, i.e., T<180 Degrees F

SV 007 Wood Storage Silo Vent #1

SV 008 Wood Storage Silo Vent #2

What to do	Why to do it
Particulate Matter < 10 micron: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Total Particulate Matter: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Opacity: less than or equal to 20 percent	Minn. R. 7011.0715
For compliance demonstration, see GP003 requirements table.	hdr

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 009 Wood Conveyor System**

Associated Items: CE 013 Fabric Filter - Low Temperature, i.e., T<180 Degrees F

SV 009 Wood Conveyor

What to do	Why to do it
Particulate Matter < 10 micron: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Total Particulate Matter: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Opacity: less than or equal to 20 percent	Minn. R. 7011.0715
For compliance demonstration, see GP003 requirements table.	hdr

TABLE A: LIMITS AND OTHER REQUIREMENTS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 010 Wood Transfer/Metering Bin**

Associated Items: CE 014 Fabric Filter - Low Temperature, i.e., T<180 Degrees F

SV 010 Wood Transfer Metering Bin

What to do	Why to do it
Particulate Matter < 10 micron: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Total Particulate Matter: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Opacity: less than or equal to 20 percent	Minn. R. 7011.0715
For compliance demonstration, see GP003 requirements table.	hdr

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 011 Emergency Generator**

Associated Items: SV 011 Emergency Generator

What to do	Why to do it
EMISSION LIMITS	hdr
Total Particulate Matter: less than or equal to 0.14 lbs/million Btu heat input	Title I Condition: BACT limit; 40 CFR 52.21(j)
Nitrogen Oxides: less than or equal to 2.88 lbs/million Btu heat input	Title I Condition: BACT limit; 40 CFR 52.21(j)
Carbon Monoxide: less than or equal to 0.85 lbs/million Btu heat input	Title I Condition: BACT limit; 40 CFR 52.21(j)
Opacity: less than or equal to 20 percent once operating temperatures have been attained.	Minn. R. 7011.2300, subp. 1
Sulfur Dioxide: less than or equal to 0.5 lbs/million Btu heat input in fuel oil.	Minn. R. 7011.2300, subp. 2
OPERATING CONDITIONS	hdr
Fuel use limited to distillate oil with a maximum of 0.5% sulfur by weight.	Minn. R. 7007.0800, subp. 2
Operating Hours: less than or equal to 500 hours/year based on a 12 month rolling sum.	40 CFR 52.21(k), Ambient Impacts Analysis
MONITORING CONDITIONS	hdr
Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of distillate oil, certifying that the sulfur content does not exceed 0.5% by weight.	Minn. R. 7007.0800, subps. 4 & 5
Record the previous month's hours of operation by the 15th of each month. Add to the preceeding 11 month's hours of operation and compare to the limit. Record the results.	Title I Condition to demonstrate compliance with limit on hours of operation
PERFORMANCE TESTING	hdr
Performance Test: due 180 days after Initial Startup for PM10, NOx, and CO. For performance test required notifications and submittals see the total facility requirements table.	Title I Condition: to determine compliance with BACT limits
NESHAP REQUIREMENTS	hdr
Within 120 calendar days after the source becomes subject to the relevant standard (initial startup), provide the following information: (i) The name and address of the owner or operator; (ii) The address (i.e., physical location) of the affected source; (iii) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;	40 CFR Section 63.6590 40 CFR Section 63.6645(d) 40 CFR Section 63.9(b)(2)(i)-(v)
(iv) A brief description of the nature, size, design, and method of operation of the source and an identification of the types of emission points within the affected source subject to the relevant standard and types of hazardous air pollutants emitted; and (v) A statement of whether the affected source is a major source or an area source.	continued from above

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **EU 012 Ash Storage Silo**

Associated Items: CE 015 Fabric Filter - Low Temperature, i.e., T<180 Degrees F

CE 016 Fabric Filter - Low Temperature, i.e., T<180 Degrees F

SV 012 Wood Ash Silo Bin Vent

What to do	Why to do it
Particulate Matter < 10 micron: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Total Particulate Matter: less than or equal to 0.002 grains/dry standard cubic foot	Title I Condition: BACT limit; 40 CFR 52.21(j)
Opacity: less than or equal to 20 percent	Minn. R. 7011.0715
For compliance demonstration, see GP003 requirements table.	hdr

TABLE A: LIMITS AND OTHER REQUIREMENTS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: FS 005 Wood Ash Loadout

What to do	Why to do it
Ash shall be wetted prior to loadout.	Title I Condition: 40 CFR 52.21(k) Ambient Impacts Analysis

TABLE A: LIMITS AND OTHER REQUIREMENTS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: FS 006 Coal Fly Ash Loadout

What to do	Why to do it
Ash shall be wetted prior to loadout.	Title I Condition: 40 CFR 52.21(k) Ambient Impacts Analysis

TABLE A: LIMITS AND OTHER REQUIREMENTS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: FS 009 Truck Traffic

What to do	Why to do it
Under dry pavement conditions, if the temperature is less than 32 degrees F, sweeping of all traffic areas is required weekly. This frequency applies only until silt load testing has been performed to determine the needed frequency for compliance with ambient standards. Sweeping is not required if the pavement is snow or ice covered.	Title I Condition: 40 CFR 52.21(k), Ambient Impacts Analysis
Under dry pavement conditions, if the temperature is greater than 32 degrees F, weekly sweeping and flushing are required. This frequency applies only until silt load testing has been performed to determine the needed frequency of sweeping or sweeping and flushing for compliance with ambient standards.	continued from above
Within 180 days of permit issuance, perform silt testing on traffic areas immediately after sweeping and flushing. Also perform silt testing on traffic areas immediately prior to re-cleaning. The frequency of cleaning required by the permit shall be determined by the time between silt testing, and shall replace the frequency given above in Conditions 1 and 2. If the maximum measured silt loading of any traffic area is greater than that assumed in the dispersion modeling used to assess ambient impacts (i.e., 2.5 grams per square meter), then the process shall be repeated until an appropriate cleaning frequency can be determined.	continued from above

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Subject Item: **MR 012**

Associated Items: EU 006 Wood Fired Boiler

What to do	Why to do it
Installation Notification: due 60 days before installing the continuous opacity monitoring system. The notification shall include plans and drawings of the system.	Minn. R. 7017.1040, subp. 1
COMS Certification Test: due 60 days after achieving maximum capacity but not later than 180 days after initial startup.	Minn. R. 7017.1050, subp. 1; 40 CFR Section 60.8(a)
COMS Certification Test Plan: due 30 days before COMS Certification Test.	Minn. R. 7017.1060, subp. 1 & 2
COMS Certification Test Pretest Meeting: due 7 days before COMS Certification Test.	Minn. R. 7017.1060, subp. 3
COMS Certification Test Report: due 45 days after COMS Certification Test.	Minn. R. 7017.1080, subp. 1, 2 & 4
COMS Certification Test Report - Microfiche or CD Copy: due 105 days after COMS Certification Test	Minn. R. 7017.1080, subp. 3
Continuous Operation: COMS must be operated and data recorded during all periods of emission unit operation including periods of emission unit start-up, shutdown, or malfunction except for periods of acceptable monitor downtime. This requirement applies whether or not a numerical emission limit applies during these periods. A COMS must not be bypassed except in emergencies where failure to bypass would endanger human health, safety, or plant equipment. Acceptable monitor downtime includes reasonable periods as listed in Items A, B, C and D of Minn. R. 7017.1090, subp. 2.	Minn. R. 7017.1090, subp. 1; 40 CFR Section 60.13(e)
Excess Emissions/Downtime Reports (EERs): due 30 days after end of each calendar quarter following initial startup.	Minn. R. 7017.1110, subp. 1; 40 CFR Section 60.7(c)
QA Plan Required: Develop and implement a written quality assurance plan which covers each COMS. The plan shall be on site and available for inspection within 30 days after monitor certification. The plan shall contain the written procedures listed in Minn. R. 7017.1210, subp. 1.	Minn. R. 7017.1210, subp. 1
COMS QA/QC: The owner or operator of an affected facility is subject to the performance specifications listed in 40 CFR pt. 60, Appendix B and shall operate, calibrate, and maintain each COMS according to the QA/QC procedures in Minn. R. 7017.1210.	40 CFR Section 60.13(a); Minn. R. 7017.1210
COMS Daily Calibration Drift Check: The Permittee must automatically, intrinsic to the opacity monitor, check the zero and upscale (span) calibration drifts at least once daily. The acceptable range is as defined in 40 CFR pt. 60, Appendix B, PS-1. The span value shall be between 60% and 80%. For COMS without automatic zero adjustments, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments. For COMS with automatic zero adjustments, the optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition as specified in 40 CFR 60.13(d)(2).	Minn. R. 7017.1210, subp. 2; 40 CFR Section 60.13(d)(l) regarding COMS and 60.13(d)(2)
COMS Calibration Error Audit: due before end of each calendar half-year following COMS Certification Test or Permit Issuance. Conduct three point calibration error audits at least 3 months apart but no greater than 8 months apart. Conduct audits in accordance with Minn. R. 7017.1210, subp. 3.	Minn. R. 7017.1210, subp. 3
Attenuator Calibration: The Permittee shall perform an attenuator calibration in accordance with Minn. R. 7017.1210, subp. y.	Minn. R. 7017.1210, subp. y
COMS Calibration Error Audit Results Summary: due 30 days after end of each calendar quarter in which the COMS calibration error audit was completed.	Minn. R. 7017.1220
All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data for each successive 6-minute period.	Minn. R. 7017.1200, subp. 1, 2 & 3; 40 CFR Section 60.13(e)(1); 40 CFR Section 60.13(h)
Recordkeeping: The owner or operator must retain records of all COMS monitoring data and support information for a period of five years from the date of the monitoring sample, measurement or report. Records shall be kept at the source.	Minn. R. 7017.1130

TABLE B: SUBMITTALS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

Table B lists most of the submittals required by this permit. Please note that some submittal requirements may appear in Table A or, if applicable, within a compliance schedule located in Table C. Table B is divided into two sections in order to separately list one-time only and recurrent submittal requirements.

Each submittal must be postmarked or received by the date specified in the applicable Table. Those submittals required by parts 7007.0100 to 7007.1850 must be certified by a responsible official, defined in Minn. R. 7007.0100, subp. 21. Other submittals shall be certified as appropriate if certification is required by an applicable rule or permit condition.

Send any application for a permit or permit amendment to:

Permit Technical Advisor
Permit Section
Air Quality Division
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155-4194

Also, where required by an applicable rule or permit condition, send to the Permit Technical Advisor notices of:
- accumulated insignificant activities,
- installation of control equipment,
- replacement of an emissions unit, and
- changes that contravene a permit term.

Unless another person is identified in the applicable Table, send all other submittals to:

Supervisor
Compliance Determination Unit
Air Quality Division
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155-4194

Send submittals that are required to be submitted to the U.S. EPA regional office to:

Mr. George Czerniak
Air and Radiation Branch
EPA Region V
77 West Jackson Boulevard
Chicago, Illinois 60604

Send submittals that are required by the Acid Rain Program to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue NW (6204N)
Washington, D.C. 20460

TABLE B: ONE TIME SUBMITTALS OR NOTIFICATIONS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

What to send	When to send	Portion of Facility Affected
Application for Permit Reissuance	due 180 days before expiration of Existing Permit	Total Facility
Notification of the Actual Date of Initial Startup	due 15 days after Initial Startup. The notification shall include the design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility.	EU006
Notification of the Date Construction Began	due 30 days after Start Of Construction. Submit the name and number of the unit and the date construction of each unit began.	EU006
Notification	due 120 days after 11/12/2004, (effective date of 40 Subp. DDDDD), for Boilers 7, 9, and 10.	Total Facility
Performance Test Notification (written)	due 60 days before Performance Test	EU006
Performance Test Plan	due 30 days before Performance Test that is a site-specific plan to the EPA Administrator and the Commissioner for review and approval according to the procedures and requirements in 40 CFR Section 63.7520.	EU006
Relative Accuracy Test Audit (RATA) Notification	due 30 days before CEMS Relative Accuracy Test Audit (RATA)	EU004
Report	due 60 days before Anticipated Date of Initial Startup that is a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the procedures and requirements in 40 CFR Section 63.7521.	EU006
Testing Frequency Plan	due 60 days after Initial Performance Test for PM10 emissions. The plan shall specify a testing frequency based on the test data and MPCA guidance. Future performance tests based on one-year (12 month), 36 month, and 60 month intervals, or as applicable, shall be required upon written approval of the MPCA.	EU001, EU003, GP003

TABLE B: RECURRENT SUBMITTALS

Facility Name: Virginia Dept of Public Utilities

Permit Number: 13700028 - 005

What to send	When to send	Portion of Facility Affected
Excess Emissions/Downtime Reports (EER's)	due 30 days after end of each calendar quarter following CEM Certification Test (Submit Deviations Reporting Form DRF-1 as amended) for NOx emissions. The EERs shall indicate all periods of exceedances of the limit including exceedances allowed by an applicable standard, i.e. during startup, shutdowns, and malfunctions.	EU004
Excess Emissions/Downtime Reports (EER's)	due 30 days after end of each calendar quarter following Initial Startup of the Monitor	GP005
Excess Emissions/Downtime Reports (EER's)	due 30 days after end of each calendar quarter following Initial Startup of the Monitor (Submit Deviations Reporting Form DRF-1 as amended). The EER shall indicate all periods of monitor bypass and all periods of exceedances of the limit including exceedances allowed by an applicable standard, i.e. during startup, shutdown, and malfunctions.	GP005
Excess Emissions/Downtime Reports (EER's)	due 30 days after end of each calendar quarter following Initial Startup of the Monitor The EER shall indicate all periods of monitor bypass and all periods of exceedances of the limit including exceedances allowed by an applicable standard, i.e. during startup, shutdown, and malfunctions.	GP004
Semiannual Deviations Report	due 30 days after end of each calendar half-year following Permit Issuance. The first report of each calendar year covers January 1 - June 30. The second report of each calendar year covers July 1 - December 31. If no deviations have occurred, the Permittee shall submit the report stating no deviations. For the Wood Fired Boiler, the report must contain the information specified in Table 9 to Subpart DDDDD of Part 63, Number 1 and 40 CFR Section 63.7550.	Total Facility
Semiannual Deviations Report	due 30 days after end of each calendar half-year following Permit Issuance. The first semiannual report submitted shall cover the calendar half-year in which the permit is issued. The first report of each calendar year covers January 1 - June 30. The second report of each calendar year covers July 1- December 31. If no deviations have occurred, submit the report stating no deviations. The report must comply with and contain the information specified in 40 CFR Section 63.7550.	EU006
Compliance Certification	due 30 days after end of each calendar year following Permit Issuance (for the previous calendar year). To be submitted on a form approved by the Commissioner, both to the Commissioner, and to the U.S. EPA regional office in Chicago. This report covers all deviations experienced during the calendar year.	Total Facility
Emissions Inventory Report	due 91 days after end of each calendar year following Permit Issuance	Total Facility

APPENDIX MATERIAL
Facility Name:Virginia Dept of Public Utilities
Permit Number: 13700028-005

Insignificant Activities Required to be Listed:

Emission Unit	Basis in 7007.1300	Applicable Regulations
Surface Grinder	Subp. 3(D)(2)	Minn. R. 7011.0710-0715
Table saw	Subp. 3(D)(2)	Minn. R. 7011.0710-0715
Welding	Subp. 3(H)(3)	Minn. R. 7011.0710-0715
Acid Bath for Drum Cleaning	Subp. 3(I)	Minn. R. 7011.0710-0715
Parts Washers	Subp. 3(I)	Minn. R. 7011.0710-0715
Ash Silo Breather Vents	Subp. 4	Minn. R. 7011.0710-0715
Enclosed Wood Unloading	Subp. 4	Minn. R. 7011.0710-0715
Wood Storage Silo	Subp. 3(I)	Minn. R. 7011.0710-0715
Wood Conveyor	Subp. 3(I)	Minn. R. 7011.0710-0715
Metering Bin	Subp. 3(I)	Minn. R. 7011.0710-0715
Wood Ash Silo	Supb. 3(I)	Minn. R. 7011.0710-0715
Coal Fly Ash Silo	Subp. 3(I)	Minn. R. 7011.0710-0715
Coal Bottom Ash Silo water wash	Subp. 3(I)	Minn. R. 7011.0710-0715
Bunker 9	Subp. 3(I)	Minn. R. 7011.0710-0715
Coal Unloading	Subp. 3(I)	
Coal Crushing	Subp. 3(I)	
Coal Conveying	Subp. 3(I)	
Coal Fly Ash Loadout	Subp. 3(I)	
Coal Bottom Ash Loadout	Subp. 3(I)	
Truck Traffic	Subp. 4	

Stack Parameters Used in Modeling

SV	Height (ft.)	Diameter (ft.)	Flow Rate (acfm)	Temperature (F)
SV002, Boiler 7	150	7	97,863	335
SV003 Boiler 9	150	5	106,860	390
SV004 Boiler 10	150	6	88,062	314
SV005 Wood Boiler	150	6.5	99,066	315
SV006 Wood Receiving	40	2.5	35,000	68
SV007 Wood Storage	60	0.67	3000	68
SV008 Wood Storage	60	0.67	3000	68
SV009 Wood Conveying	40	1	7000	68
SV010 Wood Metering	60	1	7000	68
SV012 Wood Ash Silo	55	0.75	100	68
SV014 Coal Ash Silo	8	0.67	1795	68
SV015 Coal Bottom Ash Silo Water Wash	85.7	1	2363	170
SV016 Coal Bottom Ash Bin Vent	59.1	2	20	68
SV017 Boiler 9 Bunker	96.9	1	1000	68

TECHNICAL SUPPORT DOCUMENT
For
AIR EMISSION PERMIT NO. 13700028-005

This Technical Support Document (TSD) is intended for all parties interested in the draft/proposed permit and to meet the requirements that have been set forth by the federal and state regulations (40 CFR § 70.7(a)(5) and Minn. R. 7007.0850, subp.1). The purpose of this document is to provide the legal and factual justification for each applicable requirement or policy decision considered in the determination to issue the permit.

1. General Information

1.1. Applicant and Stationary Source Location:

Owner/Operator Address and Phone Number	Facility Address (SIC Code: 4911)
City of Virginia Department of Public Utilities 618 South Second Street P.O. Box 1048 Virginia, MN 55792 Phone: 218-748-2102	City of Virginia Department of Public Utilities 618 South Second Street P.O. Box 1048 Virginia, MN 55792

Contact: Mr. Douglas J. Ganoe, Director of Operations

1.2. Description Of The Facility

The City of Virginia Department of Public Utilities is a citizen-owned utility providing steam and electricity to businesses and residents of the local Virginia area. The department currently operates any combination of three boilers using coal and/or natural gas as fuel. The three boilers are referred to as Boiler No. 7, 9, and No. 10. Boiler No. 10 is a natural gas fired boiler. Boiler No. 7 can burn both coal, sub-bituminous or bituminous, and natural gas. Boiler No. 9 is a coal only boiler. Boiler No. 8 is physically disconnected from the Utility System.

1.3 Description of the Activities Allowed By This Permit Action

This permit action is a reissuance of the Title V total facility operating permit that authorizes construction of an additional boiler and material handling equipment. Specifically, the permit authorizes the installation of a wood fired boiler to be used for district heating and electric generation. Also authorized with this permit action are the installation of wood handling and storage equipment. This modification is subject to federal new source review.

The wood fired boiler is part of a larger project that includes a wood fired boiler at Hibbing Public Utilities. Hibbing Public Utilities and Virginia Public Utilities have entered into a joint venture via formation of a third party, Laurentian Energy Authority (LEA), to generate electricity from biomass as required by an Xcel Energy purchase power agreement. LEA will lease the existing turbines to produce 15 MW at Virginia and 20 MW at Hibbing.

1.4 Description of All Amendments Issued Since the Issuance of the Last Total Facility Permit

The facility was issued a Title V total facility air emissions permit on February 5, 1998, and Amendment No. 1 to that permit was issued on December 22, 1998.

Amendment No. 1, Action No. 002: (the first amendment to the Title V permit) allowed the Utility to shut down Boiler No. 8, re-permitted coal combustion in Boiler No. 7, and permitted the venting of Boiler No. 7 through the electrostatic precipitator and stack currently used by Boiler No. 8.

Amendment No. 1 was considered a major permit amendment under Minn. R. 7007.1500, subp. 1, because the changes to the Title V permit were: 1) considered significant changes to existing monitoring, reporting, and record keeping, 2) consisted of changes made to emission limitations based on a source-specific determination of ambient impacts, and 3) consisted of changes made to underlying conditions set to avoid Prevention of Significant Deterioration (PSD) permitting.

It is important to note that new PSD permit requirements were not triggered by the addition of coal combustion to Boiler No. 7. Under 40 CFR § 52.21(b)(2)(iii)(e), the addition of a new fuel is exempt from PSD permitting as long as the unit was capable of accommodating this fuel prior to 1975 (which was the case for this boiler). The other requirement necessary to qualify for this PSD exemption is that the fuel handling system, necessary to accommodate this new fuel, had to remain in place and be capable of use with just minimal maintenance. This requirement was also met.

Amendment No. 1 eliminated the applicable requirements for Boiler No. 8 and added similar requirements for Boiler No. 7. In addition, two major changes were made to the permit. First, the Total Facility is subject to a facility-wide Nitrogen Oxide (NO_X) emission limit. That limit was set to limit total facility NO_X emissions to past actual +40 tons when Boiler No. 10 was added. While the NO_X emission limit was not changed, the emission data used in the compliance equation found in the Total Facility section of the permit was amended. The compliance equation requires emission factors for each fuel burned in each boiler. Amendment No. 1 removed the coal combustion emission factor for Boiler No. 8 and added the appropriate coal combustion emission factor for Boiler No. 7. Second, the original Title V permit contained Sulfur Dioxide (SO_2) limits for Boiler No. 7 and Boiler No. 9. The impact of SO_2 emissions on ambient air quality were remodeled as part of the permit application process because the exhaust gas dispersion parameters had changed. Boiler No. 7 will now vent to the existing Boiler No. 8 stack.

Since Boiler No. 7 is smaller and of different design than Boiler No. 8, both the exhaust gas flow rate through the stack and the SO_2 emission rate were reduced, while the stack temperature increased. These changes affect the dispersion of pollutants in the atmosphere. As a result of the ambient air quality modeling, the permitted SO_2 limit when the two coal-fired boilers are simultaneously operated was reduced. The new group operating limit is 1.6 lb/MMBtu compared to the previous permit limit of 1.72 lb/MMBtu.

The existing CEM/COM requirements for Boiler No. 8 now apply to Boiler No. 7. COM requirements have been revised only to reflect recent changes in Minnesota Rules.

Amendment No. 2, Action No. 003:

This new amendment changed a Title 1 Condition contained and pertained to the requirement to shut down Boiler No. 8. Amendment No. 1 required shutting down of Boiler No. 8 within one day of issuance of the amendment and written notification of the shutdown to the MPCA within 15 days. Initially the requirement to shut down Boiler No. 8 one day after permit issuance was appropriate, but the amendment issuance process extended into the winter heating season causing the Utility to postpone their plans to vent Boiler No. 7 to Boiler No. 8's pollution control equipment until the spring of 1999. Thus the permit condition was changed to reflect the change in construction plans.

Amendment No. 3, Action No. 004:

This amendment changed the requirement to dispersion model for NO_x and PM_{10} emissions to a requirement to just model for NO_x. Modeling information is required to be submitted for PM_{10}. This amendment also changed the dates that the NO_x modeling submittals are due.

Permit Type	Action Number	Application Date	Issue Date
Total Facility Operating Permit	001	09/18/1995	2/20/98
Major Amendment	002	9/2/1998	1/7/1999
Major Amendment	003	1/8/1999	5/6/1999
Major Amendment	004	12/24/01	10/31/2002

1.5. Facility Emissions:

Total Facility Potential to Emit Summary

	PM tpy	PM_{10} tpy	SO_2 tpy	NO_x tpy	CO tpy	VOC tpy	Single HAP tpy	*All HAPs tpy
New Wood Boiler Potential Emissions	25.19	25.19	25.19	151.1	403.0	17.13	20.1	
Total Facility Limited Potential Emissions	1157	596.7	3003	1039	1051	29.37	151.3	175
Total Facility Actual Emissions (2004)	108	40.3	324	286	140	2.19	HAPs not reported in emission inventory	

*Haps are primarily Hydrogen Chloride

Facility Classification

Classification	**Major/Affected Source**	**Synthetic Minor**	**Minor**
PSD	PM, PM_{10}, SO_2, NO_x, CO		VOC, Pb
Part 70 Permit Program	PM_{10}, SO_2, NO_x, CO, HAPs		
Part 63 NESHAP	Major		

2. Regulatory and/or Statutory Basis

<u>New Source Review</u>

The existing facility is a major source under new source review. The addition of the wood fired boiler exceeds significant emission increase levels for PM_{10}, NO_x, and CO. Accordingly, the facility was required to complete a Best Available Control Technology Analysis, and an Ambient Impacts Analysis for those pollutants. Those analyses are attached and are summarized below in Section 3.

Part 70 Permit Program

The facility is a major source under the Part 70 permit program.

New Source Performance Standards (NSPS)

The new wood fired boiler is subject to 40 CFR pt. 60, subp. Db. Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

National Emission Standards for Hazardous Air Pollutants (NESHAP)

All boilers are subject to NESHAP Standard 40 CFR pt. 63, subp. DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. The compliance date is upon startup for the new wood fired boiler. The compliance date for the existing boilers is September 13, 2007, and is specified in the permit.

Minnesota State Rules

- Minn. R. 7011.0715 Standards of Performance for Post-1969 Industrial Process Equipment
- Minn. R. 7011.2300 Standards of Performance for Stationary Internal Combustion Engines
- Minn. R. 7011.0515 Standards of Performance for Existing Indirect Heating Equipment

Compliance Assurance Monitoring, (CAM) 40 CFR Part 64

The existing coal fired boilers, Boilers 7 and 9, are subject to requirements set forth in 40 CFR pt. 64 for particulate matter and PM_{10}. The facility submitted CAM plans that focused on operation and maintenance of the electrostatic precipitators on those boilers. Staff proposed that the opacity standard set by the applicable standard (Minn. R. 7011.0510), and operation of the precipitators in a manner consistent with that during performance testing be set as permit conditions to satisfy the CAM requirements. This is similar to the compliance demonstration proposed in the applicable NESHAP standard, 40 CFR pt. 63, subp. DDDDD. Since the CAM regulations specifically exempt emission units from CAM if they are subject to a standard promulgated after November 5, 1990, (40 CFR § 64.2(b)(i)) staff determined that using a compliance demonstration method similar to subp. DDDDD (promulgated in 2004), would satisfy the CAM criteria.

Regulatory Overview of Facility

EU, GP, or SV	Applicable Regulations	Comments:
FC	Title I Condition, 40 CFR § 52.21 to limit the potential emissions increase	When Boiler 10 (gas fired) was installed, the facility took NO_x limits equal to the past actual NO_x emissions plus 39 tons per year. This led to a 73.08 tons/month limit on the total facility, based on a 12-month rolling average. This limit applies to Boilers 7, 9, and 10 (the existing facility)
FC	Minn. R. 7011.0150	Preventing particulate matter from becoming airborne
EU001-004, Boilers 7, 9, 10	40 CFR pt. 63, subp. DDDDD 40 CFR pt. 64	Compliance date is September 13, 2007. Applicable requirements will be added at that time, or at permit reissuance. Compliance Assurance Monitoring
GP001 Boilers 7 and 9	Minn. R. 7009.0020 40 CFR Part 64	Sulfur dioxide emission limits that ensure that the facility does not cause or contribute to a violation of the state sulfur dioxide ambient standard. Compliance Assurance Monitoring
EU001 Boiler 7	Minn. R. 7011.0510	Standards of Performance for Indirect Heating Equipment
EU003 Boiler 9	Minn. R. 7011.0510	Standards of Performance for Indirect Heating Equipment
EU004 Boiler 10	40 CFR pt. 60, subp. Da	Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978
EU006 Boiler 11	40 CFR pt. 60, subp. Db 40 CFR pt. 63, subp. DDDDD 40 CFR 52.21	Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, and Prevention of Significant Deterioration
EU007-10 and 12, Wood handling equipment	Minn. R. 7011.0715 40 CFR § 52.21	Standards of Performance for Post Industrial Process Equipment. Prevention of Significant Deterioration
FS009 Truck Traffic	40 CFR § 52.21(k)	Impacts Analysis: Dust control measures.

3. Technical Information

3.1 Federal Prevention of Significant Deterioration Summary BACT Analyses:

Summary:

Emission Unit	Pollutant	Emission Limit	Control Technology
EU006 Wood Boiler	PM_{10}	0.025 lb/mmBtu	Electrostatic Precipitator
	NO_x	0.15 lb/mmBtu on a 30-day rolling average	Selective Non-Catalytic Reduction
	CO	0.3 lb/mmBtu on a 4-hour block average	Good Combustion Practices
EU007-10, 12 Wood and Wood Ash Handling	PM_{10}	0.002 gr/dscf	Fabric Filter
EU011 Emergency Generator	PM_{10}	0.14 lb/mmBtu	Good Combustion Practices
	NOx	1.71 lb/mmBtu	Good Combustion Practices
	CO	0.85 lb/mmBtu	Good Combustion Practices

For all sources except the Emergency Generator, the top technically feasible option was chosen, and no financial analysis was necessary. For the Emergency Generator, controls were deemed unreasonably expensive except for ignition timing retard. (See attached BACT analysis). Ignition timing retard offers an opportunity to reduce NO_x emissions, but does so at the expense of engine efficiency. This would lead to increased fuel consumption, and corresponding increases in emissions of other pollutants, such as PM_{10}. The retarding of the engine spark can reduce engine stability, responsiveness to load demand and power output. LEA therefore suggested, and MPCA staff agreed that combustion control/good engine design be designated as BACT for NO_x.

It is also possible to lower NO_x emissions by use of a heat exchanger to cool the inlet air. It is estimated that this method could achieve a 28 percent reduction in NO_x, however costs are prohibitive for an emergency unit with minimal runtime. In addition, the water cooling option will increase the fuel demand of the engine by approximately 10 percent. Therefore, the benefit of a 28 percent decrease in NO_x is offset by a 10 percent increase in fuel consumption.

3.2 Air Quality Analysis

The installation of the wood-fired boilers is considered a major modification to each of the existing utilities, which currently have Clean Air Act Amendment Title V operating permits. The wood-fired boiler and associated emission sources will be added to the existing permits for each municipal utility. The LEA Biomass Energy Project does not modify or change the method of operation of any currently existing emission units.

The proposed boilers will be constructed in an area that is attaining the National Ambient Air Quality Standards (NAAQS)[1] [1], or is not designated. This means that federal New Source Review (NSR) Prevention of Significant Deterioration (PSD) rules must be evaluated for applicability. PSD is the permitting process by which U.S. Environmental Protection Agency (EPA), through MPCA, ensures that areas with good air quality are not degraded due to new development. Based upon total project potential emissions, it appears that PSD review is required for PM, Particulate Matter smaller than 10 microns (PM_{10}), NO_x and CO. PSD permitting requires demonstration of compliance with national ambient air quality standards based on refined air dispersion modeling, compliance with increment consumption, an analysis of additional impacts such as growth, and a Class I area impact analysis. Class I areas are areas of special national or regional natural, scenic, recreational, or historic value for which the PSD regulations are intended to provide special protection. Two Class I areas are within the review area for this project, Voyageurs National Park and the Boundary Waters Canoe Area Wilderness.

The results of the impact analysis for the Class I areas are presented below in the tables. The LEA Biomass Energy Project was shown to not have a significant impact to either Class I area.

Predicted Impact to Class I Areas for LEA Biomass Energy Project Virginia

Pollutant	Significant Impact Threshold (ug/m3)	Voyageurs National Park (ug/m3)	Boundary Waters Canoe Area (ug/m3)
PM_{10} – 24-hr standard	0.3	0.02268	0.07272
PM_{10} – Annual standard	0.2	0.00148	0.00338
NO_x – annual standard	0.1	0.00682	0.01448

Predicted Impact to Class I Areas for LEA Biomass Energy Project Hibbing

Pollutant	Significant Impact Threshold (ug/m3)	Voyageurs National Park (ug/m3)	Boundary Waters Canoe Area (ug/m3)
PM_{10} – 24-hr standard	0.3	0.01940	0.03553
PM_{10} – Annual standard	0.2	0.00112	0.00107
NO_x – annual standard	0.1	0.00521	0.00502

[1] EPA sets the **National Ambient Air Quality Standards** for pollutants considered harmful to public health and the environment. There are primary and secondary standards. ***Primary standards*** set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. ***Secondary standards*** set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings.

The modeling indicated there are no significant impacts for CO or NO_x, so additional modeling for these pollutants did not need to be performed. PM_{10} did have predicted impacts over EPA significance thresholds so air dispersion modeling was performed to demonstrate that the additional emission of PM_{10} from this project combined with all other major sources in the area (50 kilometer radius) did not contribute to an exceedance of a NAAQS standard or PSD increment allowance.

The impacts from all facilities have been evaluated for their cumulative impacts by means of the prescribed EPA model, and the total impact is compared to PSD increment and NAAQS standards. Below is a summary of the NAAQS compliance analysis and PSD increment consumption. The predicted impacts are all below the NAAQS standards and PSD increment standards.

Laurentian Energy Authority Biomass Energy Project NAAQS Compliance Summary

Pollutant	NAAQS ug/m^3	Hibbing and ALL Known Contributors ug/m^3	Virginia and ALL Known Contributors ug/m^3
PM_{10} - annual	50	45.99353	31.64045
PM_{10} – 24 hour	150	130.82701	126.99362

Laurentian Energy Authority Biomass Energy Project PSD Increment Consumption

Pollutant	Class II PSD Increment Standard ug/m^3	Hibbing and ALL Known Contributors ug/m^3	Virginia and ALL Known Contributors ug/m^3
PM_{10} - annual	17	6.06523	4.09146
PM_{10} – 24 hour	30	18.07928	24.63900

Air Impact Summary

The analysis competed as part of this assessment indicates that the proposed LEA Biomass Energy Project will not adversely affect the ambient air quality in the area.

3.3 Additional Impact Analysis

The additional impact analysis refers to completion of an environmental review which is not the same as the ambient air quality analysis discussed in Section 3.3. The environmental impact refers to review of such items as the solid or hazardous waste generation, discharges of water from a control device, visibility impacts, or emission of unregulated pollutants.

In Minnesota, new sources of emissions that have the potential to emit more than 100 tons per year of a criteria pollutant are required to complete an Environmental Assessment Worksheet (EAW). The elements of the EAW address the issues identified as part of PSD review. Please refer to the EAW submitted for this project for additional information on the environmental impact from this facility. The environmental impact issues as specified by PSD are discussed in the sections that follow.

Growth Analysis

No growth is expected from the LEA project, but maintenance of current employment status is. LEA will contract with VPU to operate and maintain the wood-fired boiler. LEA will not employ any additional staff other than that employed to operate the existing VPU facility.

Without LEA, VPU claims that inevitability its existing operation will becoming no longer cost effective and at some point the district heating system would be closed. Closure will result in loss of employment for the personnel currently operating the VPU plant.

In a situation without a centralized facility providing steam for hot water and building heat (commercial, institutional, and residential), existing customers would be forced to install alternative means for comfort heating and hot water. The impact of the numerous individual heating units required to displace the existing heating source would be have an environmental impact on the area and the ability to use the thermal load to generate electricity thereby increasing efficiency would be lost.

LEA claims that if any job growth would result in the formation of LEA, it may be in the area of forestry and logging, however, it is more likely that workers already displaced from losses in this industry would be reactivated to serve LEA. Because no growth is expected to result from this project, no growth analysis has been completed.

Soils and Vegetation Analysis

LEA project impacts are largely covered in the EAW submitted under separate cover. Per MPCA direction, no detailed analysis of soils and vegetation impacts has been undertaken. However, dispersion modeling has shown that the ambient air impacts of emissions from the LEA facility are below both the primary and secondary NAAQS. Therefore, no significant adverse impact is predicted for soils and vegetation as a result of the LEA project.

Visibility Impairment Analysis

No visibility analysis is required based on direction received from Minnesota Pollution Control Agency and Federal Land Managers.

3.4 Air Emissions Risk Analysis (AERA) Analysis

MPCA policy is to prepare an AERA as a part of the EAW process. When the potential human health risks have been calculated, the procedure is to present the AERA to the MPCA Risk Managers for a decision on the feasibility of proceeding with the project. The results of this analysis are presented below.

After consideration of all of the information provided in this AERA, the Risk Managers conclude that the facility air risk analysis is complete and that the impacts associated with the air emissions that are reasonably expected to be generated from this facility with the addition of the wood-fired boiler do not have the potential for significant environmental or health impacts.

The facility as proposed increases some toxic emissions, but using a conservative analysis and taking into account the current and anticipated demographics of the area (limited or no farming occurring within a 3 kilometer radius of the facility) leads to the conclusion that health risk values for the known air toxics are not exceeded. With the installation of the wood-fired boilers, mercury emissions will be reduced from the Laurentian project as a whole. This project also aids in attaining the objectives set forth by the Legislature to increase the use of alternative fuels with a focus on renewable energy.

Mercury Emissions

A mercury analysis is part of the AERA. Over the 20 year life of the PPA, the decrease in coal usage results in a reduction of approximately 15.7 pounds of mercury. This decrease does not occur without the LEA Biomass Energy Project.

3.5 Emission Calculations:

Potential emissions are calculated by using emission limits combined with full capacity operation for those pollutants with emission limits, and emission factors combined with full capacity operation for those pollutants without emission limits

The database used for factors for the wood boiler came from EPA’s Background Information for Section 1.6 of AP42, Wood Residue Combustion. Test data for all pollutants was averaged for all sources that had high efficiency particulate control, as it was assumed that those factors would be most accurately predictive of potential emissions from the new wood fired boiler. Some of the facilities tested had no control, cyclone control, or wet scrubbers. Data from those facilities was not used in developing average emission factors. In addition to not being similarly controlled, those boilers are most likely older than the better controlled boilers, and hence may be less efficient in relation to combustion.

AP42 factors from Section 1.1, Coal Combustion, were used to calculate emissions from the existing coal boilers.

For the material handling baghouses, the emission limits were used to calculate potential particulate and PM_{10} emissions.

For traffic emissions, AP42 equations from Section 13.2.1, Paved Roads, were used to calculate emissions. The number of fuel delivery trucks, and ash removal trucks were determined by assuming full capacity operation of all boilers, and the resulting fuel consumption and ash generation, along with the load capacity for each truck. Part of the equation is dependent on the silt content of the paved roads. The permit requires the facility to test for silt after permit issuance to verify that the silt content is not higher than that assumed in the calculations. If it is, the permit requires mitigative measures to lower the silt content on the paved areas.

For fugitive emissions from material handling, EPA's AP42 Section 13.2.4, Aggregate Handling and Storage Piles equations were used. Again, the amount of material handled was derived by assuming full capacity operation of all boilers.

3.6 Periodic Monitoring

In accordance with the Clean Air Act, it is the responsibility of the owner or operator of a facility to have sufficient knowledge of the facility to certify that the facility is in compliance with all applicable requirements.

In evaluating the monitoring requirements included in the permit, the MPCA considers the following:

- The likelihood of violating the applicable requirements;
- Whether add-on controls are necessary to meet the emission limits;
- The variability of emissions over time;
- The type of monitoring, process, maintenance, or control equipment data already available for the emission unit;
- The technical and economic feasibility of possible periodic monitoring methods; and
- The kind of monitoring found on similar units elsewhere.

The table below summarizes the periodic monitoring requirements for those emission units for which the monitoring required by the applicable requirement is nonexistent or inadequate.

Periodic Monitoring

Emission Unit or Group	Requirement (basis)	Additional Monitoring	Discussion
GP001 Boilers 7 and 9 SO_2 limits	2.5 lb/mmBtu and 1.6 lb/mmBtu	CEM	CEMs data should demonstrate continuous compliance with the emission limits
GP002 Boilers 7, 9, and 10	Monthly NO_x limit: to restrict potential emissions to less than significant increase	Monitoring of fuel use, CEMs on boiler 10, Monthly calculation of NO_x emissions.	Limit is 12 month rolling average. Emission factors for Boilers 7 and 9 are derived from tests every 2 years.
GP003 Material Handling Baghouses	Operation while emission sources are in operation and BACT emission limit	Visible emissions check, pressure drop check, stack emissions testing of one of the baghouses with the highest particulate loading	Permit also specifies inspection and maintenance. Proper operation and maintenance of the baghouses should ensure that PM limits are met for the smaller material handling sources.
EU001 Boiler 7	Minn. R. Particulate Limit	Opacity monitor, opacity limit, stack emission testing	Permit also specifies operational requirements for the electrostatic precipitator.
EU003 Boiler 9	Minn. R. Particulate Limit	Opacity monitor, opacity limit, stack emission testing	Permit also specifies operational requirements for the electrostatic precipitator. This is similar to the compliance demonstration specified by the recently promulgated boiler MACT.
EU004 Boiler 10	40 CFR Subp. Da sets PM, SO_2, NO_x and Opacity limits	Fuel use restriction to natural gas, NO_x monitor	NSPS sets compliance demonstration
EU006 Wood Fired Boiler	BACT and NESHAP Limits on PM, Opacity, CO, HCl, NOx and mercury	Opacity, CO, and NO_x CEMS, stack emission testing, operation of control equipment as during stack emission testing	Recently promulgated standard, subp. DDDDD sets most of the compliance demonstration

3.7 Insignificant Activities

Virginia Public Utilities has several operations which are classified as insignificant activities. These are listed in Appendix to the permit.

3.8 Comments Received and Response

Public Notice Period: April 28, 2005 through May 27, 2005.
EPA 45-day Review Period: April 28, 2005 through June 13, 2005.

One comment letter was received during the public comment period. That letter expressed support for the project, and did not request any changes be made to the permit.

4. Conclusion

Based on the information provided by Virginia Public Utilities, the MPCA has reasonable assurance that the proposed operation of the emission facility, as described in the Air Emission Permit No. 13700028-005, and this TSD, will not cause or contribute to a violation of applicable federal regulations and Minnesota Rules.

Staff Members on Permit Team: Jenny Reinertsen (permit writer/engineer)
Robert Beresford (enforcement)
Marshall Cole (peer reviewer)
Dave Beil (peer reviewer)

Attachments:

- BACT Analyses
- Air Quality Impact Analysis - Analysis of existing air quality, PSD increment analysis.
- Additional Impact Analysis
- RASS/AERA.
- Emission calculations

Bact Analyses

Source: Permit Application

BACT Analysis

The BACT determination has been compiled in accordance with the Top-Down BACT procedure and guidance from the DRAFT New Source Review Manual (October 1990). The RBLC database was reviewed for similar installations. Control options are then ranked from high to low control efficiencies, and technical and economic feasibilities are discussed.

RBLC Database Review

A search of the RBLC database was conducted on August 19, 2004. The RBLC database is a centralized location for BACT determination information from across the U.S. Two source categories were searched for applicable BACT determinations: 11.120 Utility Biomass Boilers and 12:120 Industrial Biomass Boilers. These lists were then pared down to develop a list of permitted processes most representative of the LEA wood-fired boiler. The BACT limitations found in the database are summarized in Table 11.

Table 11

Summary of RBLC Database Entries for Wood-Fired Boilers

RBLC ID	Company	Boiler Size MMBtu/hr	Pltnt	Limit	Units	Technology	Date
VA-0268	Martinsville Thermal	120	PM_{10}	0.14	Lb/MMBtu	Combustion Control/CEM	02/15/2002
OH-0269	Biomass Energy LLC	175	PM_{10}	0.017	Lb/MMBtu	Fabric filter	02/07/2002
CA-0930	Sierra Pacific	245.3	PM_{10}	0.035	Lb/MMBtu	Multiclone/ESP	05/13/1998
AR-0073	Potlatch Corp	159.29	PM	0.10	Lb/MMBtu	Multiclone/ESP	09/08/1995
MS-0023	Georgia Pacific	244	PM_{10}	0.10	Lb/MMBtu	None	04/11/1995
WA-0298	Sierra Pacific	310	PM	0.2	Lb/MMBtu	ESP	10/17/2002
KY-0085	Mead Westvaco	631	PM	0.1	Lb/MMBtu	ESP	02/27/2002
MN-0046	District Energy St Paul	550	PM	0.03	Lb/MMBtu	Cyclone/ESP	11/15/2001
ME-0026	Wheelabrator Sherman	315	PM	0.036	Lb/MMBtu	Cyclone/ESP	04/09/1999
NY-0055	Boralex Chateaugay	275	PM_{10}	0.038	Lb/MMBtu	Multiclone/ESP	12/19/1994
VA-0268	Martinsville Thermal	120	NO_x	0.4	Lb/MMBtu	Combustion Control/CEM	02/15/2002
OH-0269	Biomass Energy LLC	175	NO_x	0.14	Lb/MMBtu	SCR	02/07/2002
CA-0930	Sierra Pacific	245.3	NO_x	0.23	Lb/MMBtu	SNCR	05/13/1998
AR-0073	Potlatch Corp	159.29	NO_x	0.25	Lb/MMBtu	Boiler Design and operation	09/08/1995
MS-0023	Georgia Pacific	244	NO_x	0.3	Lb/MMBtu	None	04/11/1995
AR-0072	Del-Tin Fiber	291	NO_x	0.3	Lb/MMBtu	Low NOx and SNCR	02/28/2003
WA-0298	Sierra Pacific	310	NO_x	0.15	Lb/MMBtu	Boiler design/SNCR	10/17/2002
KY-0085	Mead Westvaco	631	NO_x	0.4	Lb/MMBtu	None	02/27/2002
MN-0046	District Energy St Paul	550	NO_x	0.15	Lb/MMBtu	SNCR	11/15/2001

ME-0026	Wheelabrator Sherman	315	NO_x	0.25	Lb/MMBtu	Combustion Control	04/09/1999
NY-0055	Boralex Chateaugay	275	NO_x	0.23	Lb/MMBtu	None	12/19/1994
VA-0268	Martinsville Thermal	120	CO	0.44	Lb/MMBtu	Combustion Control/CEM	02/15/2002
OH-0269	Biomass Energy LLC	175	CO	0.011	Lb/MMBtu	Oxidation Catalyst	02/07/2002
CA-0930	Sierra Pacific	245.3	CO	1.15	Lb/MMBtu	High pressure overfire air	05/13/1998
AR-0073	Potlatch Corp	159.29	CO	1.35	Lb/MMBtu	Proper Design and operation	09/08/1995
MS-0023	Georgia Pacific	244	CO	0.69	Lb/MMBtu	None	04/11/1995
AR-0072	Del-Tin Fiber	291	CO	0.78	Lb/MMBtu	Combustion Control	02/28/2003
WA-0298	Sierra Pacific	310	CO	0.35	Lb/MMBtu	Combustion Control	10/17/2002
MN-0046	District Energy St Paul	550	CO	0.3	Lb/MMBtu	Combustion Control	11/15/2001
ME-0026	Wheelabrator Sherman	315	CO	0.45	Lb/MMBtu	Combustion Control	04/09/1999
NY-0055	Boralex Chateaugay	275	CO	0.35	Lb/MMBtu	None	12/19/1994

PM_{10} Controls and Emission Limits from RBLC Database

Particulate matter controls from the RBLC database records indicate a predominance of ESP as the BACT control technology, often in combination with multiclones. Select cases utilize a fabric filter (OH-0269) or combustion control (VA-0268). BACT emission rates range from 0.017 to 0.20 pounds per million Btu, with the fabric filter controlled source (OH-0269) representing the lower end of the range. Consultation with the permitting agency, Ohio EPA indicates that this facility has never been constructed and the permit has expired. The next lowest BACT emission rate is 0.03 lbs per MMBtu from the District Energy St. Paul facility.

NOx Controls and Emission Limits from RBLC Database

Nitrogen oxide controls from the RBLC database records indicate a wide range of technologies as BACT, including no control, combustion control, SNCR and SCR. Again the most stringent control, SCR appears in the permit for RBLC record OH-0269, however that facility has not been constructed and the permit has expired. BACT emission rates range from 0.15 to 0.40 pounds per million Btu, excluding OH-0269 which has not been constructed. The lowest BACT emission rate for a constructed and operating facility is 0.15 lbs/MMBtu from the District Energy St. Paul facility, which employs SNCR technology.

CO Controls and Emission Limits from RBLC Database

Carbon monoxide controls from the RBLC database records indicate a predominance of combustion control as BACT. One determination was made for oxidation catalyst, however that facility (OH-0269) has not been constructed and the permit has expired. BACT emission rates range from 0.3 to 1.35 pounds per million Btu. The lowest BACT emission rate for a constructed and operating facility is 0.3 lbs per MMBtu from the District Energy St. Paul facility, which employs combustion control. However that emission limit has not yet been met by the facility. Willamette Industries of South Carolina also received a limit of 0.3 lbs/MMBtu; its status is currently unknown.

Summary of BACT Review Results

The RBLC review indicates BACT control technology and emission rate limitations as summarized in Table 12.

Table 12
RBLC BACT Control Technology and Emission Rate Limitations.

Pollutant	Control Technology	Emission Limitation
PM_{10}	Multiclone + ESP	0.03 lbs/MMBtu
NO_x	SNCR	0.15 lbs/MMBtu
CO	Combustion Control	0.3 lbs/MMBtu

LEA BACT For Nitrogen Oxide Control

The Top-Down BACT determination procedure requires development of a list of potential control technologies, ranked from highest control efficiency to lowest. The technologies are then reviewed, beginning with the most highly-ranked option, for technical feasibility. Those technologies that are deemed technically feasible are then reviewed, again beginning with the most effective technology, for economic feasibility. The best-performing option that meets both technical and economic feasibility is then presumed to be BACT for the project.

Ranking of Control Technologies

As can be seen in Tables 11 and 12, the use of Selective Noncatalytic Reduction (SNCR) is the standard of technology employed to control NO_x emissions from wood-fired boilers.
In general, NO_x control for solid fuel boilers may make use of Selective Catalytic Reduction (SCR), SNCR, or low-NO_x firing configurations including reburn. Table 13 provides a list of NO_x control options and their associated control efficiencies.

Table 13

Ranking of Control Technologies for NO_x Reduction

Control Technology	EPA Efficiency Range (%)
Selective Catalytic Reduction	70-90%
Selective Noncatalytic Reduction	30-50%
Combustion Control	30%

Technical Feasibility Analysis

Selective Catalytic Reduction (SCR) is the highest-performing control option in the top-down hierarchy. SCR makes use of a catalyst with ammonia injection. The catalyst improves the efficiency of the chemical reduction of NO_x by ammonia. The SCR is designed to evenly distribute the flow of NO_x across a catalyst surface, also providing thorough mixing of the injected ammonia to facilitate reduction and thus removal of NO_x. Our review of the potential use of SCR for control of NO_x from the LEA boiler finds that SCR has been uniformly rejected as a technically infeasible control option for wood-fired boilers. The higher levels of silicates and other constituents found in biomass fuels leads to rapid fouling of the catalyst bed, greatly reducing the effectiveness of the SCR system, and leading to significant down time and expense in replacing the catalyst. It is for this reason that reviewing agencies have concurred that SCR is not technically feasible for wood-fired boilers.

Selective Noncatalytic Reduction (SNCR) does not make use of catalysts to produce the reduction reaction. As such, the fouling problems that plague SCR systems do not occur with SNCR. SNCR is the top control option for control of NO_x for wood-fired boilers. LEA proposes adoption of this top technically feasible option as BACT.

LEA BACT for Carbon Monoxide Control

Options for controlling carbon monoxide emissions from solid fuel boilers are limited. Although catalysts can be used in automobiles and in some gas or oil-burning stationary engines, the catalyst fouling problems that plague SCR systems also make catalysts technically infeasible for solid fuel boilers. As illustrated in Tables 11 and 12, Combustion Control, the maintenance of good combustion practices, has been the universal BACT selection for control of CO emissions. LEA proposes adoption of the top technically feasible option of combustion control as BACT.

LEA BACT for PM_{10} Emission Control (Wood-Fired Boiler)

Table 14 provides a list of potential particulate control options for wood-fired boilers. The stoker boiler proposed for LEA will incorporate multiclones for removal of gross particulate and will follow the multiclone with an Electrostatic Precipitator (ESP). LEA proposes adoption of this option as BACT for PM_{10} control.

Table 14
Ranking of PM_{10} Control Options

Control Technology	EPA Efficiency Range (%)
Multiclone + Fabric filter	99.9 +
Multiclone + ESP	99 +
Fabric filter	95-99.9
ESP	90-99
Multiclone	30-90

The LEA boiler is being designed with multiclones. Questions have arisen as to the feasibility of utilizing the top particulate control, a fabric filter, due to threat of fire from carbonaceous ash and the potential for glowing embers to reach the fabric filter. Although several past BACT determinations, including District Energy St. Paul, indicated that the fabric filter was technically infeasible due to fire concerns, LEA originally requested bids based upon inclusion of a fabric filter. The vendors responding to the solicitation uniformly indicated that the threat of fire in the baghouse was an overwhelming concern that made the option infeasible. It is for this reason that LEA is proposing to adopt the multiclone-ESP combination as BACT for the wood-fired boiler. Documentation of vendor concerns with the fabric filter have been previously forwarded to MPCA for review.

BACT for PM_{10} Emission Control (Wood Handling Operations)

LEA proposes to select the top control option, a fabric filter, for each vented emission point in the wood handling system. This includes the Wood Receiving

Operation, Wood Conveying, Wood Storage (2 bin vents), Wood Metering Bin, and Ash Silo exhausts. An emission rate limit of 0.002 gr/scf is proposed as BACT for each emission point.

BACT for PM_{10} Emission Control (Fugitive Dust)

The LEA facility is being constructed on an existing site which already consists of paved ground. Truck traffic will occur to receive wood chips and to haul away ash from the ash storage silo. Fugitive emissions will also arise when discharging ash from the ash silo into trucks.

Road Dust Sources

The wood receiving and ash hauling traffic will transit paved ground as described earlier. BACT options then focus on reduction of silt loading on the paved areas. Dust control can be accomplished through washing and sweeping of the roadways (while temperatures allow washing without creating a safety hazard.) Table 15 summarizes the effectiveness of the various options.

Table15

Fugitive Dust Control Options for Paved Roadways

Control Option	EPA Efficiency Range (%)*
Water Flushing and Sweeping	96% or less
Water Flushing	69% or less
Vacuum Sweeping	46 – 58%
Sweeping	25 – 30%

*Efficiency values taken from "Air Pollution Engineering Manual", First Edition, Table 5, page 145.

Given the harsh climate in which LEA will operate, the application of water to roadways poses serious safety concerns during much of the year.

The facility proposes to accept a weekly washing and sweeping schedule to reduce silt loading on the facility road surfaces, using city-owned street sweepers. The weekly sweeping will continue until road silt load testing has been completed and a new sweep and/or washing schedule is developed. It is estimated that this schedule will provide approximately 50 percent reduction in road silt contents on the paved surfaces. In addition, LEA proposes the posting of a 5 mph speed limit for on site truck traffic to reduce dust generation.

Ash Loadout

Bottom and fly ash from the wood-fired boiler will be conveyed to an ash silo for on-site storage. Up to 200 trucks per year will be needed to remove the ash from the silo and transport it to a handling area off-site. Fugitive dust from the ash loadout will be suppressed through the incorporation of water with the ash as it is unloaded into the trucks.

3.2.8 BACT for Diesel-Fired Emergency Generator

Per MPCA direction, BACT for the emergency generator is also investigated for NO_x, CO and PM_{10} control. Table 16 provides a list of potential NO_x control methods for the emergency generator. Control efficiency for Selective Catalytic Reduction is taken from an Air Pollution Control Technology Fact Sheet from the EPA CATC website. Emission reduction estimate for Ignition Timing Retard is taken from "Alternative Control Techniques (ACT) Document - Internal Combustion NO_x Part 1 & 2" also found on the CATC website. Control efficiency for cooling water addition to reduce NO_x formation is from emission rate information provided by an engine manufacturer.

Table 16

Ranking of Control Technologies for NO_x Reduction

Control Technology	EPA Efficiency Range (%)
Selective Catalytic Reduction	70-90%
Cooling Water	28%
Ignition Timing Retard	~25%
Combustion Control	-

Table 17 provides a listing of control options for reducing emissions of carbon monoxide. The control efficiency for the oxidation catalyst is taken from the recent MACT discussion for reciprocating internal combustion engines.

Table 17

Ranking of Control Technologies for CO Reduction

Control Technology	EPA Efficiency Range (%)
Oxidation Catalyst	93%
Combustion Control	-

Table 18 provides a listing of control options for reducing emissions of PM_{10}. Control efficiencies are taken from EPA Air Pollution Control Fact Sheets.

Table 18

Ranking of Control Technologies for PM_{10} Reduction

Control Technology	EPA Efficiency Range (%)
Fabric Filter	95-99.9%
Electrostatic Precipitator	90-99.9%
Wet Scrubber – Packed Bed	70-99%
Wet Scrubber - Venturi	70-99%
Low Ash Fuel	-

Table 19 provides a summary of BACT decisions contained in the RBLC Database. BACT decisions dating back through 2002 are included in the summary.

Table 19

Summary of RBLC Database Entries for Emergency Generators

RBLC ID	Company	Generator Size (kW)	Pltnt	Limit	Units	Technology	Date
AR-0076	U.S. Army, Pine Bluff Arsenal	2500	PM_{10}	1.1	Lb/hr	None	02/17/2004
OK-0091	Cardinal Mfg	2000	PM_{10}	0.0444	Lb/MMBtu	Combustion Control	03/18/2003
IA-0067	MidAmerican Energy	1400	PM_{10}	0.14	Lb/MMBtu	Combustion	06/17/2003

RBLC ID	Company	Generator Size (kW)	Pltnt	Limit	Units	Technology	Date
						Control	
OK-0090	Duke Energy	500	PM_{10}	0.124	Lb/MMBtu	Combustion Control	03/21/2003
TX-0407	STEAG Power LLC	~1000	PM_{10}	2.97	Lb/hr	None	12/06/2002
IA-0060	Entergy	unknown	PM_{10}	0.34	Lb/hr	Good Combustion, Timing Retard	07/23/2002
MS-0055	El Paso Merchant Energy Co.	1735	PM_{10}	-	-	VE limit only, 60 hrs/yr operation	06/24/2002
OK-0070	Genova Oklahoma LLC	750	PM_{10}	0.033	Lb/MMBtu	Combustion Control	06/13/2002
SC-0064	SCE&G	2000	PM_{10}	1.9	Lb/hr	Combustion Control, Low sulfur fuel	05/23/2002
IA-0058	MidAmerican Energy	700	PM_{10}	0.95	Lb/hr	None	04/10/2002
AR-0076	U.S. Army, Pine Bluff Arsenal	2500	NO_x	0.0182	g/Bhp-hr	None	02/17/2004
OK-0091	Cardinal Mfg	2000	NO_x	2.035	Lb/MMBtu	Combustion Control	03/18/2003
IA-0067	MidAmerican Energy	1400	NO_x	1.71	Lb/MMBtu	Timing Retard	06/17/2003
OK-0090	Duke Energy (not constructed)	500	NO_x	2.16	Lb/MMBtu	Combustion Control, Hour of Operation Limits	03/21/2003
TX-0407	STEAG Power LLC	~1000	NO_x	14.0	g/Bhp-hr	None	12/06/2002
IA-0060	Entergy	unknown	NO_x	10.61	Lb/hr	Good Combustion, Timing Retard	07/23/2002
OK-0070	Genova Oklahoma LLC	750	NO_x	3.01	Lb/MMBtu	Combustion Control	06/13/2002
SC-0064	SCE&G	2000	NO_x	59.5	Lb/hr	None	05/23/2002
OK-0072	Redbud Energy LP	~1500	NO_x	0.024	Lb/Bhp-hr	None	05/06/2002
IA-0058	MidAmerican Energy	700	NO_x	22.69	Lb/hr	Ignition Timing Retard	04/10/2002
OK-0091	Cardinal Mfg	2000	CO	0.202	Lb/MMBtu	Combustion Control	03/18/2003
TX-0407	STEAG Power LLC	~1000	CO	3.03	g/Hp-hr	None	12/06/2002
IA-0067	MidAmerican Energy	1400	CO	0.85	Lb/MMBtu	Combustion Control	06/17/2003
OK-0090	Duke Energy	500	CO	2.66	Lb/MMBtu	Combustion Control	03/21/2003
IA-0060	Entergy	unknown	CO	0.22	Lb/hr	Good Combustion, Timing Retard	07/23/2002

OK-0070	Genova Oklahoma LLC	750	CO	0.31	Lb/MMBtu	Combustion Control	06/13/2002
SC-0064	SCE&G	2000	CO	15.8	Lb/hr	None	05/23/2002
OK-0072	Redbud Energy LP	~1500	CO	0.055	Lb/Bhp-hr	Combustion Control	05/06/2002
IA-0058	MidAmerican Energy	700	CO	2.86	Lb/hr	None	04/10/2002

3.2.8.1 PM_{10} Control Option Selection

As can be seen in Table 19, PM_{10} controls from recent BACT decisions have ranged from no control to good combustion practices/engine design. One engine, of unknown size applied timing retard. Economic analysis is conducted on each of the technically feasible control options to determine cost-effectiveness of control. This computation is summarized in Table 20.

Table 20

Summary of PM_{10} Control Cost Effectiveness for Emergency Generator

Technology	Removal Efficiency (%)	Minimum Capital Cost ($/scfm)*	Minimum O&M Cost ($/scfm)	Scfm	Unctrl TPY	Ctrl TPY	Cost Effectiveness ($/ton)**
Fabric Filter	99.9	6	5	4878	0.356	0.000356	$68,580
ESP	99.9	10	3	4878	0.356	0.000356	$41,148
Packed Bed Scrubber	99	11	15	4878	0.356	0.00356	$207,610
Venturi Scrubber	99	2.5	4.4	4878	0.356	0.00356	$60,899
Low Ash Fuel #	-	-	-	-	-	-	-

**taken from CATC Air Pollution Control Fact Sheets*
***Using O&M costs only. Annualization of capital costs not included*
 # facility already committed to using low sulfur fuel oil

From the simple analysis presented in table 20, it is clear that add-on control technologies for removal of particulate emission from the emergency generator is not cost effective. The generator is proposed with a 500 hour/year operating limitation, as well as use of low sulfur fuel oil.

3.2.8.2 NO_x Control Option Selection

As can be seen in Table 19, NO_x controls from recent BACT decisions have ranged from no control to good combustion practices/engine design. One engine, of unknown size applied timing retard. Economic analysis is conducted on each of the technically feasible control options to determine cost-effectiveness of control. This computation is summarized in Table 21.

Table 21

Summary of NO_x Control Cost Effectiveness for Emergency Generator

Technology	Removal Efficiency (%)*	Annual Cost ($/year)*	Unctrl TPY	Ctrl TPY	Cost Effectiveness ($/ton)
SCR	90	$92,220	11.4	1.14	$8,988
Cooling Water	28	$17,199	11.4	8.21	$5,388**
Ignition Timing Retard	25	$7,306	11.4	8.55	$2,564
Combustion Control	-	-	-	-	-

**ignition timing retard efficiency and all cost values taken from the EPA Document,'Alternative Control Techniques – Internal Combustion NOx', page 5-14*

***Cost analysis does not include the increased cost of fuel for the water cooling option. Water cooling will increase the hourly fuel consumption by 10.2 gallons per hour.*

It is possible to lower NOx emissions by use of a heat exchanger to cool the exhaust. It is estimated that this method could achieve a 28 percent reduction in NO_x, however costs are prohibitive for an emergency unit with minimal runtime. In addition, the water cooling option will increase the fuel demand of the engine by approximately 10 percent. Therefore, the benefit of a 28 percent decrease in NO_x is offset by a 10 percent increase in fuel consumption.

Ignition timing retard offers an opportunity to reduce NO_x emissions, but does so at the expense of engine efficiency. This would lead to increased fuel consumption, and corresponding increases in emissions of other pollutants, such as PM_{10}. The retarding of the engine spark can reduce engine stability, responsiveness to load demand and power output. LEA therefore suggests that combustion control/good engine design be designated as BACT and the vendor-guaranteed emission rate of 2.88 lbs/MMBtu be accepted as BACT for NO_x.

3.2.8.3 CO Control Option Selection

As can be seen in Table 19, CO controls from recent BACT decisions have ranged from no control to good combustion practices/engine design. One engine, of unknown size applied timing retard, however the less than optimum combustion with timing retard, more CO can be expected. Economic analysis is conducted on each of the technically feasible control options to determine cost-effectiveness of control. This computation is summarized in Table 22.

Table 22

Summary of CO Control Cost Effectiveness for Emergency Generator

Technology	Removal Efficiency (%)*	Annual Cost ($/year)**	Unctrl TPY	Ctrl TPY	Cost Effectiveness ($/ton)
Oxidation Catalyst	93	$129,240	3.03	0.21	$45,864
Combustion Control	-	-	-	-	-

**taken from RICE MACT documentation*

***costs taken from vendor quote for RICE MACT development 8.27.1998*

Cost information for oxidation catalyst applications are difficult to locate. The OAQPS Control Cost Manual does not provide estimates for CO control systems; however, cost data were located in the docket for development of the Reciprocating Internal Combustion Engine (RICE) MACT. Cost figures for the oxidation catalyst were pulled from documents in the RICE MACT docket. LEA proposes that combustion control/good engine design be considered BACT for the emergency generator for CO.

Ambient Impacts Analyses
Source: Permit Application

Ambient Air Quality Analysis

Air dispersion modeling has been completed to analyze LEA impacts on ambient air quality and is discussed in the sections that follow.

Summary of ISC-PRIME Settings

This section describes the model options selected for modeling the proposed Laurentian Energy Authority, LLC (LEA) wood-fired electric generation facility to be located at the Virginia Public Utility site. The analysis utilizes the Industrial Source Complex Short Term model with the PRIME downwash algorithm (ISC-PRIME), version 01228. The model is included within the BEEST dispersion modeling package assembled by Bowman Engineering of Asheville, North Carolina.

Terrain Option

Digitized terrain data for the project area was purchased from Micropath in the form of 30-meter DEM Quads. The Quads were stitched together and converted to NAD83 coordinates using the freeware program 3DEM. Class I area receptor grids are provided by the Federal Land Managers for Voyageur's National Park and the Boundary Waters Canoe Area.

Regulatory Default Option

The regulatory default option was used to employ the Plume Rise Model Enhancements (PRIME) algorithm for treatment building downwash. The PRIME algorithm includes enhanced dispersion coefficients due to turbulent wake, and reduced plume caused by a combination of the descending stream lines in the lee of the building and the increased entrainment in the wake.

Concentration/Deposition Option

The concentration option was used to provide maximum emission concentrations that could be compared to Ambient Air Quality Standards. The model was set to provide output in terms of receptor concentration.

Rural/Urban Option

The Auer classification scheme was used to determine land use setting for the model. Rural dispersion coefficients were selected for the area.

Model Averaging Periods

Per USEPA guidance, dispersion modeling analysis is required for those pollutants with emission increases exceeding the major modification threshold.

For the proposed LEA wood-fired electric generation facility, only the pollutants NO_x, PM_{10} and CO require dispersion modeling analysis. The following averaging periods were used for each pollutant:

- NO_x Annual
- CO 1-Hour, 8-Hour
- PM_{10} 24-Hour, Annual

Source Groups

For determination of significant impacts from the proposed facility a source group containing the proposed new LEA sources was employed (NEW_VPU). For PSD PM_{10} Increment consumption modeling, the proposed LEA sources at Virginia and Hibbing were modeled, plus increment consumers at Hibbing Taconite, Potlatch-Cook, and the Laskin Energy Center.

All sources have been relocated to NAD83 coordinates by comparing coordinate locations with digital orthophotos obtained from the Minnesota DNR Data Deli.

Emission Rates

Maximum potential emissions from the new LEA facility were used for both PSD Increment and NAAQS compliance model runs. For existing LEA sources, emissions were also modeled at potential emission rates for purposes of PSD Increment and NAAQS analysis. Sources outside of LEA were included at emission rates provided in the MPCA source inventories for PSD Increment and NAAQS.

Merging of Stacks

Merged stacks are not employed in the modeling of LEA sources. A few distant sources may be modeled such that all facility emissions are assumed to pass through a single stack, but where possible, this practice has been avoided. Stack parameters are taken from previous modeling runs identified by MPCA as a source of data.

Building Downwash Implementation

The ISC models include algorithms to model the effects of buildings downwash on emissions from nearby or adjacent point sources. The EPA Building Profile Input Program (BPIP-PRIME) version 95086 was employed to determine building downwash parameters for the LEA sources. Downwash has not been included for sources located beyond the LEA significant impact area. USEPA has recently approved the use of a new version of BPIP, however the update consists only of allocatable arrays that allow for unlimited numbers of buildings and stacks to be input. The BPIP model is included within the BEEST dispersion modeling package assembled by Bowman Engineering of Asheville, North Carolina, and has not yet implemented the minor update to BPIP.

Per guidance from MPCA, building downwash calculations should be undertaken for any sources located within 3 kilometers of the Virginia Public Utilities Site. However, none of the modeled sources lie within 3 kilometers, so building downwash is only implemented for the Virginia Public Utility – LEA site.

Meteorological Data

The meteorological data uses the most recent five years of available National Weather Service (NWS) meteorological data from the nearest site, the Hibbing surface and St. Cloud upper air observations. The information was obtained from the MPCA website and includes the years 1972-1976.

Receptor Grid Development

Significant impact modeling utilizes a large grid, extending out to 10,000 meters. Smaller grids that encompass the significant impact area of each pollutant are then used. The receptor grid employed for PM_{10} increment and NAAQS analysis is designed to exceed the PM_{10} worst-case significant impact radius, which extend to a maximum distance of 0.4 km (see Table 32). The grid utilizes 10 meter spacing on the fenceline, 25 meter spacing to 250 meters, 50 meter spacing to 500 meters, and 100 meter spacing to 1500 meters.

Varying Load Analysis Procedures

For the varying load analysis, contributions from combustion sources are scaled appropriately in terms of emission rate and volume flow, resulting in less emission but also less exit velocity or plume rise. Temperature is assumed to remain constant through the varying load scenarios. Contributions from particulate generating sources are scaled for emission rate, but volume flow would be assumed to be constant in association with operation of the fan and control equipment, not scaled to production levels. 100, 75 and 50 percent load analyses are presented.

Emergency Generators

A 1.5 MW emergency generator is proposed for the LEA Virginia site. The generator is provided solely for emergency use and will not be operated when other LEA and Virginia Public Utility sources (boilers) are operating. The generator is therefore not included in modeling of ambient air concentrations for prediction of PSD Increment or NAAQS standard compliance.

Model Results

Modeling was performed in accordance with PSD guidance. A preliminary analysis was conducted to determine whether the proposed wood-fired electric generation facility created a significant impact on ambient air quality. This analysis was conducted for CO, NO_x and PM_{10}, pollutants for which the project represents a major increase in emissions subject to PSD. The preliminary analysis determines whether in-depth modeling of PSD increment consumption and NAAQS compliance must be conducted. When a source impact is less than the significant impact threshold, the source is said to be unable to cause or contribute to an exceedence of ambient air quality standards, and the analysis goes no further. When the source is shown to have a significant impact on ambient air quality, the full impact analysis must be conducted to assess whether PSD growth increments or NAAQS might be exceeded. The discussion below provides a summary of the dispersion modeling findings for the proposed LEA wood-fired electric generation facility.

Significant Impact Area Determination and Varying Load Analysis

Nitrogen Dioxide

- **Annual Averaging Period**

  Tables 23, 24, 25 summarize the model-predicted NO_x concentrations for the 100 percent , 75 percent and 50 percent load analyses annual averaging periods. We have applied the EPA Tier II analysis procedure, by multiplying NO_x concentrations by 75 percent to predict NO_2 concentations for comparison with significant impact thresholds. The 100 percent load scenario presents the highest concentrations in each of the five years. In all five years, regardless of load scenario, the impact from the new facility is not predicted to exceed the significant impact threshold of 1 microgram per cubic meter. Full impact modeling for NO_x is therefore not required for PSD Increment and NAAQS compliance based upon the annual averaging period.

Table 23
ISC-PRIME Results for 100% Load Nitrogen Dioxide Impacts
Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y	Impact Radius (km)*
1972	0.93750	535600	5262000	2.5
1973	0.77750	535600	5262000	1.6
1974	0.84460	535600	5262000	2.4
1975	0.83018	535600	5262000	1.6
1976	0.97024	535600	5262000	2.9

**Impact radius measured from 534552, 5263264, the wood boiler stack location.*

Table 24
ISC-PRIME Results for 75% Load Nitrogen Dioxide Impact
Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y	Impact Radius (km)
1972	0.84016	535600	5262000	1.6
1973	0.69682	535600	5262000	-
1974	0.75724	535600	5262000	1.6
1975	0.74199	535600	5262000	-
1976	0.87606	535600	5262000	2.5

**Impact radius measured from 534552, 5263264, the wood boiler stack location.*

Table 25
ISC-PRIME Results for 50% Load Nitrogen Dioxide Impacts Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y	Impact Radius (km)
1972	0.67071	535600	5262000	-
1973	0.55461	535600	5262000	-
1974	0.60038	535600	5262000	-
1975	0.58634	535600	5262000	-
1976	0.70442	535600	5262000	-

**Impact radius measured from 534552, 5263264, the wood boiler stack location.*

Carbon Monoxide

- **1-Hour Averaging Period**
  Tables 26, 27, 28 summarize the model-predicted CO concentrations for the 1-hour averaging period for 100 percent, 75 percent and 50 percent load scenarios. In all scenarios and in all five years, the impact from the new facility is not predicted to exceed the significant impact threshold of 2,000 micrograms per cubic meter. Full impact modeling for CO is therefore not required for NAAQS compliance based upon the 1-hour averaging period.

Table 26
ISC-PRIME Results for 100% Load Carbon Monoxide Impacts 1-Hour Averaging Period

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y	Impact Radius (km)**
1972	319.77859	05/31/21	535500	5263600	-
1973	313.53317	07/03/24	535500	5263600	-
1974	307.75378	06/19/22	535500	5263700	-
1975	314.81525	09/04/01	535400	5263700	-
1976	311.15924	07/17/23	535600	5263500	-

**period notation refers to the time period during which the high value occurred (day/mo/hr)*

***Impact radius measured from 534552, 5263264, the wood boiler stack location.*

Table 27
ISC-PRIME Results for 75% Load Carbon Monoxide Impacts
1-Hour Averaging Period

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y	Impact Radius (km)**
1972	281.62744	08/31/22	535400	5263700	-
1973	269.99490	05/30/22	535300	5263900	-
1974	274.31534	08/12/01	535400	5263700	-
1975	279.30334	09/04/01	535400	5263700	-
1976	277.28833	08/24/21	535200	5264000	-

**period notation refers to the time period during which the high value occurred (day/mo/hr)*
***Impact radius measured from 534552, 5263264, the wood boiler stack location.*

Table 28
ISC-PRIME Results for 50% Load Carbon Monoxide Impacts
1-Hour Averaging Period

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y	Impact Radius (km)**
1972	242.05490	08/27/21	535500	5263600	-
1973	235.63995	10/12/24	535400	5263700	-
1974	241.05255	08/12/01	535400	5263700	-
1975	233.40553	10/19/22	535400	5263700	-
1976	231.57983	08/24/21	535200	5264000	-

**period notation refers to the time period during which the high value occurred (day/mo/hr)*
***Impact radius measured from 534552, 5263264, the wood boiler stack location.*

- **8-Hour Averaging Period**

  Tables 29, 30, 31 summarize the model-predicted CO concentrations for the 8-hour averaging period for 100 percent, 75 percent and 50 percent load scenarios. In all load scenarios and in all five years, the impact from the new facility is not predicted to exceed the significant impact threshold of 500 micrograms per cubic meter. Full impact modeling for CO is therefore not required for NAAQS compliance based upon the 8-hour averaging period.

Table 29
ISC-PRIME Results for 100% Load Carbon Monoxide Impacts - 8-Hour Averaging Period

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y	Impact Radius (km)**
1972	105.75436	09/20/24	535300	5263800	-
1973	93.43497	09/27/24	535200	5264000	-
1974	124.84381	01/04/08	535400	5263800	-
1975	87.18205	08/25/24	535400	5263800	-
1976	86.40488	04/15/08	535600	5263600	-

**period notation refers to the time period during which the high value occurred (day/mo/hr)*
***Impact radius measured from 534552, 5263264, the wood boiler stack location.*

Table 30
ISC-PRIME Results for 75% Load Carbon Monoxide Impacts 8-Hour Averaging Period

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y	Impact Radius (km)**
1972	95.58295	09/20/24	535300	5263800	-
1973	86.01434	09/27/24	535200	5264000	-
1974	11122760	01/04/08	535400	5263800	-
1975	79.04321	02/19/24	535200	5264100	-
1976	78.56760	04/15/08	535600	5263600	-

**period notation refers to the time period during which the high value occurred (day/mo/hr)*
***Impact radius measured from 534552, 5263264, the wood boiler stack location.*

Table 31
ISC-PRIME Results for 50% Load Carbon Monoxide Impacts 8-Hour Averaging Period

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y	Impact Radius (km)**
1972	76.10345	09/20/24	535300	5263800	-
1973	72.09935	09/27/24	535200	5264000	-
1974	88.14828	01/04/08	535400	5263800	-
1975	63.21714	02/19/24	535200	5264100	-
1976	67.71464	07/17/24	535600	5263400	-

**period notation refers to the time period during which the high value occurred (day/mo/hr)*
***Impact radius measured from 534552, 5263264, the wood boiler stack location.*

Particulate Matter (PM_{10})

- **Annual Averaging Period**

  Tables 32, 33, 34 summarize the model-predicted PM_{10} concentrations for the annual averaging period for 100 percent , 75 percent and 50 percent load scenarios. The 100 percent load scenario presents the highest concentrations in each of the five years. In all five years, regardless of load scenario, the impact from the new facility is predicted to exceed the significant impact threshold of 1 microgram per cubic meter. Full impact modeling must therefore be conducted for PM_{10} PSD Increment and NAAQS compliance.

Table 32
ISC-PRIME Results for 100% Load PM10 Impacts
Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y	Impact Radius (km)**
1972	3.52140	534584	5263248.50	0.2
1973	3.51454	534526.81	5263209	0.2
1974	3.79100	534584	5263248.50	0.2
1975	3.34543	534584	5263238.50	0.2
1976	3.94195	534584	5263238.50	0.2

***Impact radius measured from 534528.8, 5263259, the midpoint of PM10 sources.*

Table 33
ISC-PRIME Results for 75% Load PM10 Impacts
Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y	Impact Radius (km)**
1972	2.13968	534526.81	5263209	0.1
1973	2.19457	534526.81	5263209	0.1
1974	2.15984	534526.81	5263209	0.1
1975	1.91679	534526.81	5263209	0.1
1976	2.29183	534526.81	5263209	0.1

***Impact radius measured from 534528.8, 5263259, the midpoint of PM10 sources*

Table 34
ISC-PRIME Results for 50% Load PM10 Impacts
Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y	Impact Radius (km)**
1972	1.76396	534584	5263248.50	0.1
1973	1.75982	534526.81	5263209	0.1
1974	1.89898	534584	5263248.50	0.1
1975	1.67380	534584	5263238.50	0.1
1976	1.97260	534584	5263238.50	0.1

***Impact radius measured from 534528.8, 5263259, the midpoint of PM10 sources*

- **24-Hour Averaging Period**

Tables 35, 36, 37 summarize the model-predicted PM_{10} concentrations for the 24-hour averaging period for 100 percent, 75 percent and 50 percent load scenarios. The 100 percent load scenario presents the highest concentrations in each of the five years. In all five years, regardless of load scenario, the impact from the new facility is predicted to exceed the significant impact threshold of 5 micrograms per cubic meter. Full impact modeling must therefore be conducted for PM_{10} PSD Increment and NAAQS compliance.

Table 35
ISC-PRIME Results for 100% Load PM10 Impacts
24-Hour Averaging Period

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y	Impact Radius (km)**
1972	22.80936	03/05/24	534584	5263248.50	0.3
1973	21.37071	03/19.24	534498.19	5263209	0.4
1974	20.19672	04/07/24	534517.19	5263209	0.3
1975	30.29222	04/15/24	534584	5263248.50	0.4
1976	24.63876	04/25/24	534517.19	5263209	0.4

**period notation refers to the time period during which the high value occurred (day/mo/hr)*
***Impact radius measured from 534528.8, 5263259, the midpoint of PM10 sources*

Table 36

ISC-PRIME Results for 75% Load PM10 Impacts

24-Hour Averaging Period

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y	Impact Radius (km)**
1972	12.70259	03/17/24	534526.81	5263209	0.2
1973	12.86357	04/25.24	534526.81	5263209	0.3
1974	12.74803	04/15/24	534526.81	5263209	0.2
1975	12.90228	03/06/24	534536.31	5263209	0.3
1976	15.05986	04/26/24	534517.19	5263209	0.4

**period notation refers to the time period during which the high value occurred (day/mo/hr)*

***Impact radius measured from 534528.8, 5263259, the midpoint of PM10 sources*

Table 37

ISC-PRIME Results for 50% Load PM10 Impact

24-Hour Averaging Period

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y	Impact Radius (km)**
1972	11.44398	03/05/24	534584	5263248.50	0.1
1973	10.71868	03/19.24	534498.19	5263209	0.1
1974	10.11756	04/07/24	534517.19	5263209	0.1
1975	15.13928	04/15/24	534584	5263248.50	0.1
1976	12.34016	04/25/24	534517.19	5263209	0.1

**period notation refers to the time period during which the high value occurred (day/mo/hr)*

***Impact radius measured from 534528.8, 5263259, the midpoint of PM10 sources*

PSD Increment Consumption – All Increment-Consuming Sources

Particulate Matter (PM_{10})

- **Annual Averaging Period**

  Table 38 summarizes the model-predicted PM_{10} concentrations for all increment consuming sources. In all five years, predicted increment consumption is less than the Class II PSD Increment standard of 17 micrograms per cubic meter..

Table 38
Summary of PM10 PSD Increment Consumption (All Sources)
Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y
1972	3.67092	534584	5263248.50
1973	3.72163	534526.81	5263209
1974	3.98185	534584	5263248.50
1975	3.51515	534584	5263238.50
1976	4.09146	534584	5263238.50

- **24-Hour Averaging Period**

  Table 39 summarizes the model-predicted PM_{10} concentrations for all increment consuming sources. In all five years, predicted increment consumption is less than the Class II PSD Increment standard of 30 micrograms per cubic meter.

Table 39
Summary of PM10 PSD Increment Consumption (All Sources)
24-Hour Averaging Period-Highest Second High

Year	Highest-High Concentration (ug/m3)	Period*	Receptor X	Receptor Y
1972	21.35614	03/02/24	534584	5263248.50
1973	21.15425	03/18/24	534507.69	5263209
1974	19.04542	04/02/24	534526.81	5263209
1975	23.88190	03/0824	534584	5263248.50
1976	24.63900	04/25/24	534517.19	5263209

**period notation refers to the time period during which the high value occurred (day/mo/hr)*

Particulate Matter (PM_{10})

- **Annual Averaging Period**

  Table 40 summarizes the model-predicted PM_{10} concentrations for the annual averaging period for NAAQS compliance by all identified sources within 50 kilometers.

Table 40
Summary of PM10 NAAQS Compliance (All Sources)
Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y
1976	15.64045	534584	5263238.50

- ### Background Concentrations

  Background concentration was provided by MPCA. The MPCA-specified background concentration for annual PM_{10} is 16 micrograms per cubic meter. When added to the highest concentration from the NAAQS model, a value of 31.64045 micrograms per cubic meter is predicted, well below the NAAQS standard of 50 micrograms per cubic meter.

- ### 24-Hour Averaging Period

  Table 41 summarizes the model-predicted PM_{10} concentrations for the 24-hour averaging period for NAAQS compliance by all identified point sources within 50 kilometers.

Table 41
Summary of PM10 NAAQS Compliance (All Sources)
24-Hour Averaging Period – High Sixth High/5 Years

Year	H6H Concentration (ug/m3)	Period*	Receptor X	Receptor Y
1976	89.99362	09/14/24	533100	5264900

**period notation refers to the time period during which the high value occurred (day/mo/hr)*

- ### Background Concentrations

  Background concentration was provided by MPCA. The MPCA-specified background concentration for 24-hour PM_{10} is 37 micrograms per cubic meter. When added to the highest concentration from the NAAQS model, a value of 126.99362 micrograms per cubic meter is predicted, below the NAAQ standard of 150 micrograms per cubic meter.

Additional Impact Analysis

Source: Permit Application

Additional Impact Analysis

The additional impact analysis refers to completion of an environmental review which is not the same as the ambient air quality analysis discussed in Section 3.3. The environmental impact refers to review of such items as the solid or hazardous waste generation, discharges of water from a control device, visibility impacts, or emission of unregulated pollutants.

In Minnesota, new sources of emissions that have the potential to emit more than 100 tons per year of a criteria pollutant are required to complete an environmental assessment worksheet (EAW). The elements of the EAW address the issues identified as part of PSD review. Please refer to the EAW submitted for this project for additional information on the environmental impact from this facility. The environmental impact issues as specified by PSD are discussed in the sections that follow.

Growth Analysis

No growth is expected from the LEA project, just maintenance of current employment status of the area. LEA will contract with VPU to operate and maintain the wood-fired boiler. LEA will not employ any additional staff than what is already employed to operate the existing VPU facility.

Without LEA, VPU is faced with the inevitability that its existing operation is becoming no longer cost effective and at some point the district heating system would be closed. Closure will result in loss of employment for the personnel currently operating the VPU plant.

In addition, instead of a centralized facility providing steam for hot water and building heat (commercial, institutional, and residential), existing customers would be forced to install alternative means for comfort heating and hot water. The impact of the numerous individual heating units required to displace the existing heating source would be a considerable environmental impact to the area and the ability to use the thermal load to generate electricity thereby increasing efficiency would be lost.

If any job growth would result in the formation of LEA, it may be in the area of forestry and logging, however, it is more likely that workers displaced from losses in this industry would be reactivated to serve LEA. In all, no growth of employment is expected, just maintenance of current levels. Maintenance of current employment levels in Minnesota's more rural areas makes good state-wide sense for protecting the environment. Rural workers displaced tend to move to more metropolitan areas such as the Twin Cities where it is perceived employment opportunities and social programs are more readily available. Additional population in the metropolitan area will result in additional environmental impact in areas that are already under environmental stress. Because no growth is expected to result from this project, no growth analysis has been completed.

Soils and Vegetation Analysis

LEA project impacts are largely covered in the EAW submitted under separate cover. Per MPCA direction, no detailed analysis of soils and vegetation impacts has been undertaken. However, dispersion modeling has shown that the ambient air impacts of emissions from the LEA facility are below both the primary and secondary NAAQS. Therefore, no significant adverse impact is predicted for soils and vegetation as a result of the LEA project.

Visibility Impairment Analysis

No visibility analysis is required based on direction received from Minnesota Pollution Control Agency and Federal Land Managers.

Conclusion

The environmental impact posed by this project is considered to be a net benefit for the following reasons:

- Retention of existing population due to maintenance of employment opportunities.
- Offsetting of coal combustion currently used for electrical generation.
- Maintenance of district heating system will prevent individual smaller, unregulated and uncontrolled heating units from being installed in the area.
- Reduction of GHG emissions.
- Replacing fossil fuel with renewable fuel to meet areas energy demands

Class I Area Impact Analysis

Impacts on Class I Areas

The Boundary Waters Canoe Area (BWCA) and Voyageur's National Park (VNP) Class I areas are located approximately 55 kilometers from the proposed LEA source at Virginia, Minnesota. Nitrogen dioxide, PM_{10} and carbon monoxide impacts were modeled using ISC-PRIME. A receptor grid for each class I area was obtained from the federal land managers. The grid coordinates were converted to NAD83 UTM using the CORPSCON program.

Nitrogen Dioxide

- **Annual Averaging Period**

  Table 42 summarizes the model-predicted NO_x concentrations for the BWCA Class I Area for the annual averaging period. The highest predicted concentration is 0.01448 micrograms per cubic meter.

Table 42
ISC-PRIME Predicted Impacts in BWCA Class I Area - Nitrogen Dioxide
Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y
1972	0.01448	548853.19	5308624.5
1973	0.00892	563823.69	5305992
1974	0.01267	548853.19	5308624.5
1975	0.01407	548853.19	5308624.5
1976	0.01133	563793.19	5308770.5

Table 43 summarizes the model-predicted NO_x concentrations for the VNP Class I Area for the annual averaging period. The highest predicted concentration is 0.00682 micrograms per cubic meter.

Table 43
. ISC-PRIME Predicted Impacts in VNP Class I Area - Nitrogen Dioxide
Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y
1972	0.00609	532410.44	5353895
1973	0.00592	538598.75	5352081
1974	0.00557	532410.44	5353895
1975	0.00682	531175.31	5353888
1976	0.00481	532410.44	5353895

Particulate Matter (PM10)

- **Annual Averaging Period**

Table 44 summarizes the model-predicted PM_{10} concentrations for the BWCA Class I Area for the annual averaging period. The highest predicted concentration is 0.00338 micrograms per cubic meter.

Table 44
ISC-PRIME Predicted Impacts in BWCA Class I Area – PM10 Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y
1972	0.00338	548853.19	5308624.5
1973	0.00177	563823.69	5305992.0
1974	0.00306	548853.19	5308624.5
1975	0.00338	548853.19	5308624.5
1976	0.00267	546985.19	5308609.0

Table 45 summarizes the model-predicted PM_{10} concentrations for the VNP Class I Area for the annual averaging period. The highest predicted concentration is 0.00148 micrograms per cubic meter.

Table 45
.ISC-PRIME Predicted Impacts in VNP Class I Area – PM10 Annual Averaging Period

Year	High Concentration (ug/m3)	Receptor X	Receptor Y
1972	0.00135	532410.44	5353895
1973	0.00125	532410.44	5353895
1974	0.00123	532410.44	5353895
1975	0.00148	531175.31	5353888
1976	0.00106	532410.44	5353895

- **24-Hour Averaging Period**

Table 46 summarizes the model-predicted PM_{10} concentrations for the BWCA Class I Area for the 24-hour averaging period. The highest predicted concentration is 0.07272 micrograms per cubic meter.

Table 46

ISC-PRIME Predicted Impacts in BWCA Class I Area – PM10
24-Hour Averaging Period

Year	*Highest-High Concentration (ug/m3)*	*Period**	*Receptor X*	*Receptor Y*
1972	0.05203	12/04/24	563823.69	5305992.0
1973	0.05924	01/24/24	546918.12	5316944.5
1974	0.07272	01/01/24	548853.19	5308624.5
1975	0.06099	02/20/24	546985.69	5308609.0
1976	0.05835	08/24/24	548853.19	5308624.5

**period notation refers to the time period during which the high value occurred (day/mo/hr)*

Table 47 summarizes the model-predicted PM_{10} concentrations for the VNP Class I Area for the 24-hour averaging period. The highest predicted concentration is 0.02268 micrograms per cubic meter.

Table 47

. ISC-PRIME Predicted Impacts in VNP Class I Area – PM10
24-Hour Averaging Period

Year	*Highest-High Concentration (ug/m3)*	*Period**	*Receptor X*	*Receptor Y*
1972	0.02347	10/20/24	533601.88	5361312.5
1973	0.02246	01/12/24	529920.69	5357586.5
1974	0.01910	01/13/24	516332.56	5361236.5
1975	0.02268	01/23/24	513861.09	5353082.5
1976	0.01626	09/11/24	516332.56	5361236.5

**period notation refers to the time period during which the high value occurred (day/mo/hr)*

AERA Results

1a) AQ Facility ID No.: 13700028
1b) AQ File No.: 622
2) Facility Name: Laurentian Energy Authority, LLC; City of Virginia Department of Public Utilities
3) Date of Submittal:
4) Date Form Completed:
4a) Project Team Members: Jenny Reinertsen, Dennis Becker, Vanessa Ranck, Chuck Stroebel (MDH)
5) Date of Risk Management Recommendation

6. General Information

- Virginia Department of Public Utilities (VDPU) is in downtown Virginia and has been in operation since the early 1900's.
- VDPU is a district heating system that provides steam for comfort heating and currently generates electricity in relationship to the steam demand.
- VDPU currently has steam driven turbines with the ability to produce 31 MW.
- Three existing boilers: two coal and one natural gas.
- Power purchase agreement (PPA) between Laurentian and Xcel requires production of 35 MW. Since neither facility can produce 35 MW alone Hibbing and Virginia have united for the project.
- Virginia is dedicating approximately 15 MW of electrical generation to Xcel from one wood-fired boiler with supplemental steam produced from existing boilers
- There will be a 12.4% reduction in coal use for both facilities over the life of the PPA.
- The project will result in a reduction of 15.7 pounds of mercury emissions from both facilities combined (based on projected actuals) over the 20 years of this analysis.
- Since the wood-fired boiler will not be at capacity until the open loop biomass is 100 percent available (5 years) the steam required to generate the required electricity will be supplemented by the existing boilers.
- Closed loop biomass will be harvested within a 100 mile radius of plant
- The proposed boiler will burn open loop biomass generated from the forest industry residue before the closed loop wood is ready.
- Emissions from the proposed boiler are based on permitted potential-to-emit (PTE).

The second table below was extracted by MPCA from data submitted by the facility in the RASS. Emissions assessed for include:

- proposed wood boiler
- wood unloading
- wood conveying
- wood storage bin
- wood transfer/metering bin
- wood ash silo

7. Total Facility at maximum capacity: One wood boiler as well as two existing coal boilers

Air Toxics Screen											
Total Inhalation Screening Hazard Indices and Cancer Risks				Total Indirect Pathway Screening Hazard Indices and Cancer Risks				Total Multipathway Screening Hazard Indices and Cancer Risks			
Acute [1]	Subchronic Noncancer [1]	Chronic Noncancer [1]	Cancer [2]	Farmer Noncancer [1]	Farmer Cancer [2]	Resident Noncancer [1]	Resident Cancer [2]	Farmer Noncancer [1]	Farmer Cancer [2]	Resident Noncancer [1]	Resident Cancer [2]
3.7E-01	2.3E-02	1.6E-01	5.9E-06	2.3E-04	4.2E-04		7.4E-07	1.6E-01	4.3E-04	1.6E-01	6.6E-06
OK	OK	OK	OK	OK	REFINE		OK	OK	REFINE	OK	OK

[1] Threshold or acceptable level for acute, subchronic and chronic noncancer hazard indices is 1.0
[2] Threshold or acceptable level for cancer risk is 1.0E-05 .

Wood ONLY (new project)

Air Toxics Screen											
Total Inhalation Screening Hazard Indices and Cancer Risks				Total Indirect Pathway Screening Hazard Indices and Cancer Risks				Total Multipathway Screening Hazard Indices and Cancer Risks			
Acute [1]	Subchronic Noncancer [1]	Chronic Noncancer [1]	Cancer [2]	Farmer Noncancer [1]	Farmer Cancer [2]	Resident Noncancer [1]	Resident Cancer [2]	Farmer Noncancer [1]	Farmer Cancer [2]	Resident Noncancer [1]	Resident Cancer [2]
1.0E-01	4.3E-03	6.6E-02	1.4E-06	4.1E-05	2.1E-04		6.2E-07	6.6E-02	2.1E-04	6.6E-02	2.0E-06
OK	OK	OK	OK	OK	REFINE		OK	OK	REFINE	OK	OK

[1] Threshold or acceptable level for acute, subchronic and chronic noncancer hazard indices is 1.0
[2] Threshold or acceptable level for cancer risk is 1.0E-05 .

8. Summary of Components:
Risk Assessment (Total Facility):

- o Cancer risks and hazard indices are below thresholds for the inhalation pathway.
- o Farmer cancer risks are at 4E-04 as modeled, however information provided by the facility states that there are no farms within a three kilometer radius from the facility.
- o High one-hour concentrations are predicted to occur northeast of the facility, in an area of old mines.
- o High annual values are predicted to occur in residential neighborhoods to the southeast of the facility.
- o Access to the facility is limited, but receptors are close because of the facility's location.
- o Persistent, bioaccumulative and toxic chemicals are emitted.
- o There are four fishable lakes near the facility.

The Laurentian Energy Authority (LEA) estimates that there will be a 12.4 percent reduction in coal consumption from both facilities (VDPU and HPU) over the life of the power purchase agreement (PPA). There will not be a reduction in coal consumption at the outset of the project since additional steam will be needed to satisfy the PPA prior to the wood-fired boiler being on-line and at full capacity with open loop and closed loop biomass. In other words, the PPA stipulates that LEA will be required to meet the megawatt requirement immediately. The estimate of this of consumption reduction (12.4%) comes from coal use projections made by LEA and the owner's engineer, the Harris Group.

Dispersion Modeling: Acceptable
Dispersion factors reflect the MPCA DISPERSE batch program (acceptable model, receptors, meteorology, and land use land cover data), or more conservative MPCA RASS/DISPERSE look-up table. Larger sources (e.g., coal and wood-fired boilers) used the DISPERSE batch program. Smaller particulate-only sources used the DISPERSE look-up table. Some small particulate emission sources were not included in the RASS (e.g., traffic).

As part of the federal PSD requirements (40 CFR 52.21), full particulate matter less than 10 microns (PM_{10}) and Nitrogen Oxide (NOx) modeling was completed. PSD air dispersion modeling considers all facility sources, other nearby sources, and background concentrations.

Emission Calculations:
The database used came from EPA's Background Information for Section 1.6 of AP42, Wood Residue Combustion. Test data for all pollutants were averaged for all sources that had high efficiency particulate control, as it was assumed that those factors would be most accurately predictive of potential emissions from the new wood-fired boiler. Some of the facilities tested had no control, cyclone control, or wet scrubbers. Data from those facilities were not used in developing average emission factors. In addition

to not being similarly controlled, those boilers are most likely older than the better controlled boilers, and hence may be less efficient in relation to combustion.

AP42 factors from Section 1.1, Coal Combustion, were used to calculate emissions from the existing coal boilers. For the material handling baghouses, the emission limits were used to calculate potential particulate and PM_{10} emissions. For fugitive emissions from material handling, EPA's AP42 Section 13.2.4, Aggregate Handling and Storage Piles equations were used. Again, the amount of material handled was derived by assuming full capacity operation of all boilers.

Potential emissions are calculated by using emission limits combined with full capacity operation for those pollutants with emission limits, and emission factors combined with full capacity operation for those pollutants without emission limits

Hourly emission rates were calculated assuming full capacity operation. Annual emissions are obtained by assuming continuous operation 8760 hours per year. Annual emissions are typically reported in tons. To convert lbs/hour into tons/year the emission rate must be multiplied by 8760 and then divided by 2000 (amount of pounds in a ton). This method for calculating potential emission is conservative, since most emission units are designed to operate at a higher capacity then what will be utilized.

MDH:
MDH participated in the review of the LEA Virginia Public Utilities AERA. MDH's comments have been incorporated throughout this report.

EMISSIONS:

9. Were PTE or future projected actuals used for any or all of the emissions or scenarios?
Permitted PTE: Permitted PTE is the maximum capacity of the facility to emit, taking into account enforceable emission limits and any physical limits on operation.

10. Percent mass assessed in each RASS analysis.

Analysis Description	% VOC	% HAPs
PTE	23.1%	99.8%

Previous AERAs have assessed 2 to 22 percent of VOCs, primarily for ethanol facilities. The AERAs completed to date have assessed 76 to 100 percent of the HAPs.

11. Total mass assessed for each emissions dataset (tons/year).

Analysis Description	Total VOC	Total HAPs	Total Criteria Pollutants
PTE	22.6	176.1	5158.4

CHEMICALS

12. Are there any potentially missing chemicals or sources from the RASS? Yes
The following sources were not quantitatively evaluated in the AERA:

- Emission increases related to shutdowns and breakdowns
- Emergency internal combustion engine
- Natural gas only boiler (Boiler #10)
- Insignificant activities or those sources that have potential emissions less than 1% for particulate matter:
  - Fugitive dust from truck traffic
  - Ash silo vents
  - Fugitive dust from ash load-out, and coal handling activities from existing facility.

AERA guidance excludes activities listed above from AERA review. For additional information, see Section 2.3.2 on page 15 of the AERA Guide.

Based on the emission factor sources used in the assessment, there are no missing chemicals in the COPI list.

9. If thresholds have been exceeded, list the chemicals that contribute to the elevated hazard indices and the percent to which they contribute. Total cancer risk is 4.3E-04

Total Farmer Cancer	Cancer Risk	percent contribution
Arsenic Compounds	1.2E-06	0.3%
Chromium Compounds	2.2E-06	0.5%
Hexachlorodibenzodioxins, All Congeners	1.4E-06	0.3%
Indeno(1,2,3-cd)pyrene	1.3E-06	0.3%
Pentachlorodibenzodioxins, All Congeners	2.4E-04	53.3%
Pentachlorodibenzofurans, All Congeners	2.9E-05	6.4%
Tetrachlorodibenzodioxins, All Congeners	1.5E-04	33.3%
Tetrachlorodibenzodioxin, 2,3,7,8-	1.5E-05	3.3%
Tetrachlorodibenzofurans, All Congeners	3.2E-06	0.7%
Tetrachlorodibenzofuran, 2,3,7,8-	1.5E-05	3.3%

9. List chemicals emitted but lacking inhalation health benchmarks

Acetophenone	Cobalt	Dinitrophenol, 2,4-
Nitrophenol, 4-	Acenaphthene	Acenaphthylene
Acetone	Anthracene	Benzaldehyde
Benzo(e)pyrene	Benzo(g,h,I) perylene	Benzoic Acid
Bromomethane	Carbazole	Chloromethane
2-Chloronaphthalene	2-Chlorophenol	Crotonaldehyde
Decachlorobyphenyl	1,2-Dichloroethene	Dichlorobiphenyl
1,2-Dichloroethane	Fluoranthene	Fluorene
Heptachlorobiphenyl	Hexachlorobiphenyl	Hexanal
Isobutyraldehyde	Methane	2-Methylnaphthalene
Monochlorobiphenyl	2-Nitrophenol	Pentachlorobiphenyl
Perylene	Phenanthrene	Propanal
Propionaldehyde	Pyrene	Tetrachlorobiphenyl
Tetrachloroethene	o-Tolualdehyde	p-Tolualdehyde
Trichlorobiphenyl	Trichloroethene	Iron
Molybdenum	Phosphorus	Potassium
Silver	Sodium	Strontium
Tin	Titanium	Vanadium
Yttrium	3-Methylchloranthrene	Biphenyl
Pentane	5-Methyl Chrysene	Dimethyl sulfate-
Methyl hydrazine	Butane	Ethane
Propane		

9. Are respiratory sensitizers emitted? Yes **Are there respiratory sensitizers emitted that lack IHBs?** Yes

Beryllium, beryllium compounds, formaldehyde, nickel and nickel compounds are emitted. These chemicals do not exceed inhalation health benchmarks. There are no respiratory sensitizers that are potentially emitted that lack inhalation health benchmarks.

10. Are developmental toxicants emitted? Yes **Are any above the 1 hour inhalation health benchmark ceiling values?** No

The following chemicals are the developmental toxicants emitted at the Virginia public utility: arsenic, arsenic compounds, benzene, carbon disulfide, carbon tetrachloride, chloroform, ethyl benzene, ethyl chloride, mercury and mercury compounds. No developmental toxicants are above one-hour inhalation health benchmarks.

11. Mercury Analysis:

This mercury analysis is for the LEA project as a whole and incorporates information from both the Hibbing and Virginia facilities. Unlike the rest of the AERA, the mercury analysis assesses mercury emissions based on future projected actuals.

This project consists of the construction of two new wood-fired boilers. Each boiler will be located at existing public utilities where coal-fired boilers will continue to operate.

Mercury emission limits apply to both the new wood-fired and the existing coal-fired boilers. The Industrial Boiler NESHAP, adopted by EPA in September 2004 imposes a mercury emission limit immediately upon startup of any new boiler, including the proposed wood boilers at Virginia and Hibbing, and requires the existing coal-fired boilers be in compliance with the limit in 2007.

Stack testing of the existing boilers has been completed and shows compliance with the boilers' applicable mercury emission limit in the industrial boiler NESHAP. The data used to develop emission estimates of actual and "future actual" conditions for the existing boilers relies on this stack test data, and can be considered an accurate estimate of actual emissions. One method of removing mercury from coal-fired boilers is to ensure that the flue gases have some carbon in the particulate matter for the mercury to adsorb to. The carbon is then removed in particulate controls downstream of the boilers. "Loss on ignition" (LOI) measurements on bottom and fly ash measure the amount of unburned carbon remaining in the ash. It is hypothesized that this unburned carbon acts as an inherent control of mercury. Hibbing Public Utility staff reports that their recent test of fly ash shows its LOI to be about 24.5% by weight, representing a fly ash that is nearly one-quarter carbon, which could be providing some mercury control. Improved particulate matter capture could significantly lower mercury emissions from the existing coal boilers simply by removing more particulate to which mercury is already adsorbed. Virginia boilers are expected to be performing similarly.

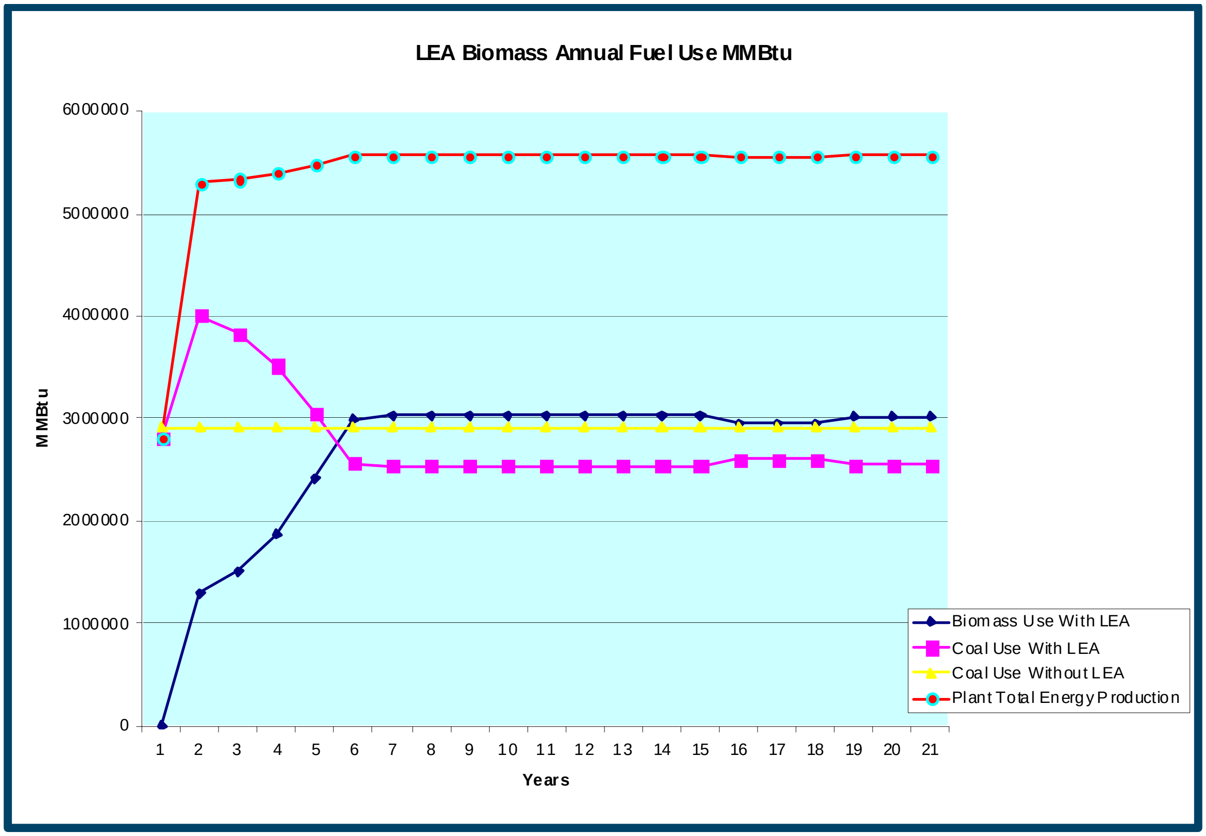
Wood-fired boiler PTE have also been calculated using the limit imposed by the industrial boiler rule.

This project in the long-term will reduce the amount of coal used at the two municipal utilities, however, between years 1 and 5 after the wood-fired boilers begin operating, coal use will go up fairly significantly in order to meet LEA's purchase power agreement with Minnesota Power. Coal use will initially increase from an annual rate of approximately 2,810,988 to 4,004,320 MMBtu. During operating years 1 through 5, the availability and use of biomass fuel will increase, decreasing the amount of coal used to meet LEA's generating requirements. Coal use will decrease to about 2,500,000 MMBtu/year at year 6 and remain at about that level for the life of the project.

Figure 1 below shows the use of coal both with and without the LEA project. Because biomass fuel is displacing coal, over the life of the project, less mercury is emitted than if the existing coal fired boilers continued operating as they are today. The project will result in 15.7 lbs of mercury avoided over the 20 years of this analysis.

Mercury species from boilers is mostly elemental, meaning that mercury released from the coal and wood boiler stacks will likely join the regional and global pool rather than deposit locally. This project results in total net reduction in mercury emissions at the fuel use levels evaluated in this project, demonstrating an important characteristic in the application of biomass fuels for electricity generation.

Figure 1. Fuel Use at Laurentian Energy, years 1 to 20.



12. Should separating toxicity endpoints be considered for a refined risk assessment after the AERA process? No

The primary risks associated with this facility are cancer risks and separating endpoints would not refine the risk assessment.

13. What are the direct $PM_{2.5}$ emissions, if applicable?

According to USEPA, combustion is one of the largest *point* sources of fine particulate emissions. Using the 2002 Emission Inventory data, the actual direct $PM_{2.5}$ emissions from the Virginia facility are at 29,206.12 pounds (14.6 tons) per year. The current actual emissions are based on the combustion sources that currently operate at the Virginia facility and do not include the proposed project.

The additional boiler will increase the $PM_{2.5}$ emissions likely from the facility. In addition, the increased truck traffic to the facility will also add to particulate matter impacts. EPA's PM Calculator is used to estimate the amount of direct $PM_{2.5}$ emissions that are coming from a source. For some sources, the amount of direct $PM_{2.5}$ emitted is a ratio of the PM_{10} emitted.

Primary or direct $PM_{2.5}$ emissions, which are noted here, are expected to behave like other air toxics gases that are commonly modeled and assessed. Primary $PM_{2.5}$ is of more concern for local deposition than secondary $PM_{2.5}$. Secondary $PM_{2.5}$ forms at a significant distance from the facility. The $PM_{2.5}$ precursor gases, which for some types of facilities may ultimately contribute to more $PM_{2.5}$ in the ambient air, are a greater concern regionally.

14. Are the criteria pollutants compared to the AAQS using "high first high" modeled concentrations?

Yes, the highest annual concentrations are used in the RASS for comparison to the AAQS. For regulatory purposes, the annual AAQS are compared with the maximum annual concentrations (a.k.a. High-1st-High [H1H] values), and the short-term (24 hours or less) AAQS are compared with special non-maximum concentrations (e.g., H2H values for short-term SO2 AAQS; H6H 24-hour PM_{10} values when using 5 years of meteorological data). Although the PM AAQS is exceeded below, regulatory methods were not used.

15. What are the ratios of criteria pollutants to their AAQS?

Criteria Pollutant Screen					
Chemical	**Fraction of 1-hr std**	**Fraction of 3-hr std**	**Fraction of 24-hr std**	**Fraction of qtrly std**	**Fraction of annual std**
SO_2	**0.253**	**0.341**	**0.460**		**0.308**
PM_{10}			**1.260**		**1.007**
$PM_{2.5}$					
NO_x					**0.066**
CO	**0.004**				
Pb				**0.001**	

Criteria pollutants modeled for the Virginia facility were below the National Ambient Air Quality Standards with the exception of PM_{10}. Current data at the Virginia monitoring site show that monitored levels of PM_{10} for both annual and 24 hour levels are below standards. The addition of the wood boiler to this facility will increase the amount of criteria pollutants in the ambient air. See number 30 below for specific values from monitoring data.

Criteria pollutants have health effects that will impact health effects from toxics emitted at the facility. Total additive effects of these chemicals are not known.

9. a. Were surrogate inhalation health benchmarks used for risk drivers? Yes **Which ones?**

Arsenic Compounds
Chromium Compounds
Hexachlorodibenzodioxins, All Congeners
Pentachlorodibenzodioxins, All Congeners
Pentachlorodibenzofurans, All Congeners
Tetrachlorodibenzodioxins, All Congeners
Tetrachlorodibenzofurans, All Congeners

The chromium compounds toxicity value is a surrogate value based on chromic acid mists and dissolved chromium VI aerosols. It is likely that this would over predict the risk from the mixture named chromium compounds.

For the dioxin and furan surrogates, there is an over prediction of risk. The surrogate toxicity values for dioxins and furans are based on the most potent carcinogen congener of the particular class, e.g. penta, hexa, tetra.

b. Are surrogate toxicity values used for other chemicals that could impact the assessment (e.g. PAHs)? No

MAPS

10. Are there sensitive receptors within one kilometer from the facility? Yes

The surrounding area is comprised of businesses and residences which include sensitive receptors. The facility provided a list of four schools, one hospital, three nursing homes, and eighteen daycares. The junior and senior high schools are only two blocks away from the facility. There is a school and several licensed day cares that are near the modeled annual high concentration areas.

There are three parks and athletic fields are within one kilometer from the facility.

11. Is there evidence the land in the area of impact will not be used for agriculture (farming, livestock, etc.)? Yes

Based on an ArcView GIS map using 2000 data there are pasture areas and row crops on the far western edge of a 3 kilometer radius surrounding the facility. Information provided by the facility states that there are no farms within a three kilometer radius from the facility. Modeled annual highs are in residential neighborhoods, where farming is unlikely to occur.

12. How far away is the nearest fishable water body? Right next to the facility. **Could there be an impact based on chemicals emitted and distance?** Yes

There are four lakes within a three kilometer distance from the Virginia facility. The Virginia facility sits on Silver Lake and is near Virginia Lake, known also as Bailey Lake. Manganika Lake and Mashkenode Lake are both outside of the city, but within three kilometers of the facility. All lakes are fishable lakes and there is evidence that fishing does occur. There is no restricted access to the lakes and three lakes have boating access.

MPCA did not assess impacts to fishable water bodies from the Virginia facility. MPCA staff are currently reviewing chemical fate and transport models for the purpose of estimating screening concentrations in water bodies and in fish that could result from facility air emissions. Due to the dynamic nature of a large number of variables that come into play in predicting uptake to fish (e.g. watershed to waterbody size ratio, turnover rate of waterbody, permeability of watershed soils, and many other parameters), the fate and transport models under consideration have not yet been determined by MPCA staff to provide conservative estimates of fish uptake while not providing unrealistically high estimates. Therefore the fish consumption pathway was not evaluated quantitatively.

13. What other permitted facilities are located within a one mile radius of the facility?

There are three additional permitted facilities within a one-mile radius from the Virginia facility, these point sources are the Virginia Regional Medical Center, Staver Foundry Co., and Bordens Chemical.

14. Census Blocks. 2000 census populations residing in census blocks within the facility impact area. Include demographical information.

The population of Virginia is 9157 according to 2000 census data. There are around 88 people per square mile living in the city of Virginia. It is estimated that sixteen percent of the population of Virginia is at or below poverty. Please see attached census maps for additional information.

ADDITIONAL INFORMATION

15. Accidental Release information (Incident Management System data on facility reports of SSM events from the last 5 years). Additional information as relevant.

There were two complaints in the last five years regarding the Virginia facility. Both complaints were in the summer of 2000 and were about coal dust from the facility. At the time, the complaint stated that truck traffic greatly increased the coal dust emissions. Truck routes have been altered since that time. The dust from the facility was also reported to come from dumping the coal outside and storage outdoors. The facility no longer unloads or stores coal outside.

16. Internal Combustion Engines. (AERA-04 Certification for Emergency Internal Combustion Engines)

The Virginia facility is putting in one emergency generator using #2 diesel fuel. The stack height is 3.6 meters and is located behind one of the facility's buildings (see attached map). The building has a height of almost 90 feet. The testing frequency for the emergency generator is 1 hour per week. The maximum hours permitted for this generator are 500 hours.

See AERA-04 Form for additional information.

17. What monitoring station(s) would provide representative ambient air toxic or criteria pollutant concentrations in the vicinity of the facility? Summarize monitoring results.

Air monitoring equipment is located on the Virginia City Hall Building at 327 1st St S. Air toxics including VOCs, carbonyls and metals were monitored in Virginia from October 1999 through September 2000. Metals and particulate matter (total suspended particulate, PM_{10} and $PM_{2.5}$) are currently collected in Virginia.

Levels of some metals such as iron and cobalt were higher, although not above benchmarks, in Virginia and Silver Bay than in other regions of the state. This may be due to the mining activities that occur in the region.

In 1999-2000, carbon tetrachloride and formaldehyde were monitored at levels above risk thresholds for cancer. Since that time, levels of carbon tetrachloride at monitoring locations around the state have been decreasing due to a production phase-out in 1996. It is unlikely that current carbon tetrachloride levels are above benchmark values. Formaldehyde concentrations are above risk thresholds for cancer at all Minnesota monitoring sites. The largest sources of direct emissions of formaldehyde are mobile sources and uncontrolled wood burning.

Ethylene dibromide concentrations were below the detection limit of MPCA's analytical equipment. The health benchmark for ethylene dibromide is also lower than the detection limit; therefore, it is possible that ethylene dibromide concentrations were above benchmark values.

The table below shows 1999-2000 monitored concentration and risk values for VOCs and carbonyls. The modeled increased risk for the new facility is also listed. All chemicals in this table were *monitored* at the Virginia monitoring site and were also *modeled* for the VDPU facility.

Chemicals monitored and on COPI list	Monitored Values from the Ambient Station			Modeled Increase Based on Facility Emissions	
	Average Concentration (ug/m3)	Cancer Risk 10^{-5}	Chronic Noncancer HQ	Cancer Risk 10^{-5}	Chronic Noncancer HQ
Benzene	0.87	0.68	0.03	0.00	0.001
Carbon tetrachloride	***0.67***	***1.01***	0.02	0.00	0.000
Chlorobenzene	<0.13*		<0.0001*		0.000
Chloroform	<0.09*		<0.0003*		0.000
Ethyl benzene	0.34		0.0003		0.000
Ethylene dibromide (Dibromoethane)	***<0.16****	***<3.5****	***<0.018****	0.00	0.000
Formaldehyde	***1.61***	***2.10***	0.54	0.00	0.002
Styrene	0.20		0.0002		0.000
Tetrachloroethylene (Perchloroethylene)	<0.1*	<0.06*	<0.003*	0.00	0.000
Toluene	1.78		0.004		0.000
Trichlorofluoromethane (CFC-11)	1.45		0.002		
Vinyl chloride	<0.18*	<0.16*	<0.002	0.00	0.000
Xylenes	1.57		0.02		0.000

*below detection levels

The table below shows 2003 monitored concentration and risk values for metals. The modeled increased risk for the new facility is also listed.

Chemicals monitored and on COPI list	Monitored Values			Modeled Increase	
	Average Concentration (ug/m3)	Cancer Risk 10^{-5}	Chronic Noncancer HQ	Cancer Risk 10^{-5}	Chronic Noncancer HQ
Barium	0.013*		0.027*		0.002
Cadmium	0.0018*	0.31*	0.088*	0.00	0.002
Chromium (Total)	***0.0018****	***2.2****	0.018*	.03	0.023
Lead	0.010*	0.013*		0.00	
Manganese	0.064		0.32		0.027
Nickel	0.0010*	0.047*	0.020*	0.00	0.004
Selenium	0.0014*		0.0001*		0.000
Zinc	0.0058*				

* below detection levels

Total chromium was over the health benchmark for chromium VI. However, monitoring in California and nation-wide monitoring for EPA's pilot city study indicates that chromium VI concentrations tend to be 30-50 times lower than total chromium concentrations unless there is a nearby source of chromium VI. If similar ratios are found in Minnesota, chromium VI concentrations would be expected to be well below heath benchmarks.

All of the particle concentrations measured at Virginia are below standards. The standard for PM_{10} is 150 µg/m^3 (24 hour) and 50 µg/m^3 (annual). The standard for $PM_{2.5}$ is 65 µg/m^3 (24 hour) and 15 µg/m^3 (annual).

Monitored Concentrations of Particulates in µg/m^3, 2000-2004						
Year	**TSP**		**PM_{10}**		**$PM_{2.5}$**	
	Max 24-Hour	**Annual Average**	**Max 24-Hour**	**Annual Average**	**Max 24-Hour**	**Annual Average**
2000	125	33	31	15	24	7.5
2001	74	30	29	14	20	6.8
2002	90	39	56	17	34	7.0
2003	111	40	72	18	21	6.4
2004	76	32	36	14	18	5.5

No Minnesota monitoring data are available for PAHs or POM.

Urban areas generally have higher concentrations of air toxics that are associated with motor vehicles. These compounds include acetaldehyde, benzene, ethylebenzene, formaldehyde, toluene and xylenes. As with many of the individual pollutants, the total cumulative risk tended to increase somewhat with population. The correlation was better for cancer risk than noncancer risk. While population is an important indicator of risk, other factors such as point sources and monitor location are also important.

9. What multimedia issues may need to be addressed? How are multimedia pathways relevant to this facility?

See # 24 and # 25 for additional information on the multimedia pathway.

10. Describe any community concerns:

Community concerns were found through the incident management system data maintained by MPCA as well as from conversations during a site visit to the facility. Based on complaints made to the MPCA community members are concerned about the truck traffic at the plant. Truck routes have been altered to minimize impacts to community members but it is unknown if this will eliminate concerns. In the past, there have been two complaints reported to MPCA about the blowing dust from the facility (see incident management question above). Even with the mitigative measures that the facility took, there were still concerns. There are businesses directly across from the facility, so this may remain an issue.

11. Other Relevant Information:

Virginia Department of Public Utilities is partnering with the Hibbing Public Utility to lease boilers to Laurentian Energy in a twenty year contract to sell electricity to Xcel's grid. The production of electricity via the Laurentian Energy Authority will help fulfill Xcel's mandate to produce 30% of their electricity from biomass.

STANDARDS

12. Do the emission units in the assessment have a state or federal standard? Yes **Specifically, what NESHAP applies, if any?**

All boilers are subject to the NESHAP standard 40 CFR 63, Subp. DDDDD. The new boiler will be subject upon startup, and the existing boilers will be subject to the standard by the compliance date September 23, 2007 (approximately 2.5 years from now). The new boiler, therefore, has MACT controls.

13. If the project proposer shows that risk is above threshold, was feasible and reasonable control used?

The new boilers will be subject to federal new source review, and NESHAP regulations. This means that they will be fitted with both Best Available Control Technology and Maximum Achievable Control Technology. The existing boilers are fitted with electrostatic precipitators for particulate control, and burn low sulfur coal for sulfur dioxide control. The existing boilers are not being modified, and under new source review, are not considered part of the project.

Describe the overall conservativeness of the assessment with regard to:

a) Emission estimates:

Hourly emission rates were calculated assuming full capacity operation. Annual emissions are obtained by assuming continuous operation 8760 hours per year. Annual emissions are typically reported in tons. To convert lbs/hour into tons/year the emission rate must be multiplied by 8760 and then divided by 2000 (amount of pounds in a ton). This method for calculating potential emission is conservative, since most emission units are designed to operate at a higher capacity then what will be utilized.

b) Dispersion modeling:

Dispersion modeling is slightly conservative due to unpaired events. Dispersion factors are probably conservative due to unpaired events. Unpaired events mean maximum impacts are added together even though they may actually occur at different times or different locations. The conservatism due to unpaired events is probably fairly small at LEA-Virginia due to the close proximity and considerable dispersion similarity of the existing coal-fired boilers; this is somewhat less important for the new (well controlled) wood-fired boiler.

c) Risk:

The chronic cancer inhalation risk was based on 70 years of exposure to maximum air concentrations. The surrogate toxicity values used for the risk drivers may over-predict the risks for several of the exposure scenarios. The multipathway analysis is a screening assessment designed to be conservative. A quantitative analysis for the fish consumption pathway for the four lakes within a 3-kilometer radius of the facility is not included in this assessment. The health risks in this assessment also do not account for health risks from criteria pollutants.

Considerations for analysis:

1. *Issues that can be clarified through a refined analysis:*
   A fish pathway analysis may provide more information for multipathway risk.

2. Additional review and refinement of risk driver emission factors would clarify the analysis. Refined dispersion modeling could be performed to refine risks.

3. *Issues that a refined analysis will not resolve:* None

4. *Issues for informational purposes only:* Obtaining information on risks from direct emissions of particulates from this facility was not assessed.

Staff Recommendations:

The assessment was performed in accordance with the AERA guidance. After consideration of all of the submittals, MPCA staff considers the quantitative risk evaluation for the chemicals assessed to be acceptable. Qualitative information mitigates the risk from the farmer cancer scenario as no farmers were noted in the impact area from this facility. A refined risk assessment could inform the analysis on the risks from the four fishable lakes within areas of impact from the facility.

Are there permit requirements necessary for this facility? Include draft language.
No permit requirements were required to address issues identified in the AERA but new requirements associated with the addition of the wood boiler will be required in the permit.

Risk Management recommendation and rationale:
After consideration of all of the information provided in this AERA the Risk Managers conclude that the facility air risk analysis is complete and that the impacts associated with the air emissions, that are reasonably expected to be generated from this facility with the addition of the wood fired boiler, do not have the potential for significant environmental or health impacts.

The facility as proposed increases some toxic emissions but using a conservative analysis and taking into account the current and anticipated demographics of the area (limited or no farming occurring within a 3 kilometer radius of the facility) health risk values for the known air toxics are not exceeded. With the installation of the wood fired boilers mercury emissions will be reduced from the Laurentian project as a whole. This project also aids in attaining the objectives set forth by the Legislature to increase the use of alternative fuels with a focus on renewable energy.

Section Manager Signature and Date:

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Calculations