Form 1100-1
(R 2/01)

NATURAL RESOURCES BOARD AGENDA ITEM

Item No. _____

SUBJECT: Order AM-17-05, authorization for hearing on creation of NR 428.20 to 428.27 concerning NOx RACT rules and associated reference incorporations into NR 484.04.

FOR: January 07 Board Meeting

TO BE PRESENTED BY: Larry Bruss / Regional Pollutant and Mobile Source Section Chief

SUMMARY: The Clean Air Act requires the implementation of reasonably available control technology (RACT) on major sources of NO_x emissions in the moderate nonattainment counties by 2009. To develop the proposed rules, the Department used the flexibility that EPA allows in creating RACT rules. However, these proposed rules do not exceed federal Clean Air Act requirements.

The proposed RACT rules require emission limits and good combustion technology for emission units at facilities with the potential to emit of 100 tons of NO_x per year in the counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan. The source categories include electric utility boilers, industrial sized boilers, combustion turbines, glass and steel furnaces, reciprocating engines, and other miscellaneous large combustion processes. As many as 59 emission units in these counties may be subject to the emission limits in the proposed rule. The potentially affected sources emit approximately 42,000 tons per year of NOx (2002 emission levels). The RACT emission limits will reduce emissions by approximately 30,000 tons of NOx per year by May 1, 2013. The maximum control cost (from uncontrolled levels) for all affected sources will be approximately $2,500 per ton of NO_x removed. The combustion requirements may affect an additional 60 smaller emission units. The combustion requirements will reduce emissions by an additional 40 tons of NOx per year. The Department estimates that the combustion requirements, due to the increased efficiency of the units, will actually reduce costs for affected sources by up to $500 per ton of NOx removed.

Of the 42,000 tons/year of emissions in the seven county area, coal fired boilers at electric utilities emit approximately 40,000 tons per year. This source category is subject to emission limits achieving 50 – 90% control at a cost between $1,000 and $2,200 per ton of NO_x removed. The implementation of emission limits for the electric utility boiler sector is phased-in with an interim emission limit by May 1, 2009 and the RACT emission limit by May 1, 2013 to account for engineering and equipment installation timeframes and reliability issues.

The stringency of the emission limits and the May 1, 2009 compliance date may be items of controversy in developing the RACT rules.

RECOMMENDATION: Authorization for public hearings.

LIST OF ATTACHED MATERIALS:

No ☐	Fiscal Estimate Required	Yes ☒	Attached
No ☒	Environmental Assessment or Impact Statement Required	Yes ☐	Attached
No ☐	Background Memo	Yes ☒	Attached

APPROVED:

_____ _____
Bureau Director, Kevin Kessler Date

_____ _____
Administrator, Al Shea Date

_____ _____
Secretary, Scott Hassett Date

cc: Amy Lemberger - AD/5
Carol Turner - LS/5
K. Kessler - AM/7
R. Eckdale - AM/7 (10)
Tom Karman - AM/7

STAFF REVIEW - DNR BOARD AGENDA ITEM

REMINDER

Have the following questions been answered under the summary section of this form?

- -Why is the rule needed?
- -What are the significant changes?
- -What are the key issues/controversies?
- -What was the last action of the Board?

LIST OF ATTACHED REFERENCE MATERIAL REQUIRED FOR RULE PROPOSALS:

Hearing authorization:

Background memo (if needed)*
Fiscal Estimate
Environmental Assessment (if needed)
Rule

Final adoption:

Background Memo (if needed)*
Response Summary
Fiscal Estimate
Environmental Assessment (if needed)
Rule

* If all the questions listed in the REMINDER section above can be adequately summarized on the Green Sheet (and a second sheet if needed), the Background Memo may be omitted.

Unit	Reviewer	Date	Comments
Environmental Analysis and Review			
Management and Budget			
Legal Services -Program Attorney -Carol Turner			
Other (if applicable)			

ORDER OF THE STATE OF WISCONSIN
NATURAL RESOURCES BOARD
AMENDING AND CREATING RULES

The Wisconsin Natural Resources Board proposes an order to **amend** NR 428.04(2)(h)1. and 2., 428.05(3)(e)1. to 4. and 484.04(13), (21m)(d), and (27) and **create** NR 428 Subch. IV and NR 484.04 (15m),(16m) and (26m)(cm) relating to implementation of Reasonably Available Control Technology (RACT) NO_x emission limitations applicable to major sources in the 8-Hour ozone non-attainment area in southeastern Wisconsin.

AM-17-05

Summary Prepared by the Department of Natural Resources

1. **Statute interpreted:** s. 285.11(6), Stats. The State Implementation Plan developed under s. 285.11(6), Stats., is revised.

2. **Statutory authority:** s. 227.11(2)(a) and 285.11(1) and (6), Stats.

3. **Explanation of agency authority:** Section 227.11(2)(a), Stats., gives state agencies general rule-making authority. Section 285.11(1) Stats., gives the Department the authority to promulgate rules consistent with ch. 285, Stats. Section 285.11(6), Stats., authorizes the Department to develop and revise a state implementation plan for the prevention, abatement and control of air pollution.

4. **Related statute or rule:** The current provisions of ch. NR 428 established nitrogen oxide emission limits for new and existing facilities which are located in the 1-hour ozone non-attainment counties. The primary intent in creating these past provisions of ch. NR 428 was to fulfill Clean Air Act (CAA) requirements for demonstrating rate-of-progress towards attaining the 1-hour ozone standard. The proposed rule will create a new subchapter in ch. NR 428 for purposes of establishing Reasonably Available Control Technology (RACT) emission limitations for major sources of nitrogen oxide emissions in counties designated as nonattainment under the 8-hour ozone standard. Modifications are also proposed to existing portions of NR 428 in relation to the creation of the new subchapter and in s. NR 484.04 to reflect incorporation by reference of standards.

5. **Plain language analysis:** The Clean Air Act requires states to adopt and implement a control program of reasonably available control technology (RACT) for major NO_x stationary sources in the moderate ozone nonattainment area. To meet this requirement the proposed rule establishes emission limitations and combustion tuning requirements for emission units at facilities with a total potential to emit 100 tons of NO_x in total for all emission units.

The proposed emission limits apply to electric utility generating units and larger industrial emission units. The rule also proposes combustion requirements for all emission units capable of firing 50 mmbtu/hr or greater of fuel (including those with emission limits). Both the emission limit and combustion requirements are applicable based on the unit operating more than 5 to 10% of capacity over the ozone season. The source categories affected by the rule include industrial boilers, combustion turbines, glass and steel furnaces, reciprocating engines, and other miscellaneous large combustion processes.

The rule provides compliance flexibility by providing phased implementation for electric generation units subject to CAIR, emissions averaging programs, alternative RACT determinations, demonstration of

CAIR actions satisfying RACT emission limits, and a reliability waiver option.

The primary requirement for most sources in demonstrating compliance with the emission rate limits is to install and operate continuous emissions monitoring systems. However, for several source categories which have low variability in emissions, the monitoring requirement is periodic stack testing. Compliance with good combustion requirements is demonstrated through various levels of combustion flue gas monitoring and continuous or period combustion tuning. The rule allows an owner to request an alternative to any of the emissions monitoring or good combustion requirements.

6. **Summary of, and comparison with, existing or proposed federal regulation:** In 2004, the federal NO_x SIP Call became effective in 21 eastern states requiring control of NO_x emissions. However, the NOx SIP call did not apply to Wisconsin. The sources affected by the SIP call include electric utility generating units greater than 25 megawatts and very large industrial emission units. The USEPA estimated the average cost in meeting the NO_x SIP call requirements to be approximately $2,000 per ton of controled NO_x emissions and described this cost level as highly cost-effective NO_x control. The Wisconsin NO_x RACT rule is based on considering controls with a cost ceiling of $2,500 per ton of NO_x.

The EPA is requiring implementation of best available retrofit technology (BART) control by 2013 to reduce NOx emissions from certain large emission sources which have visibility impacts in scenic Class I areas. The BART requirement is a case-by-case determination and therefore cannot be accurately represented for this discussion. However, EPA assumes default BART controls resulting in approximately 50% to 90% reduction in NO_x emissions. The proposed emission limits in the Wisconsin rule are similar and do not exceed an anticipated 90% reduction for similar sources.

The proposed RACT rule proposes emission limits for the type of industrial sources that would be affected by federal NOx SIP Call or BART requirements. The proposed emission limits for industrial sources reflect a control cost range of approximately $500 to $2,500 per ton of NO_x removed. The proposed controls for electric utility generating sources reflect a cost range of approximately $1,000 to $2,200 per ton of NO_x.The proposed emission limits in the Wisconsin rule are similar to default BART levels and do not exceed an anticipated 90% reduction for similar sources. It should be noted that both the NOx SIP Call and BART requlations primarily affect larger sources and that the proposed RACT rule establishes emission limits for additional sources based on the CAA definition of a major sources.

7. **Comparison with rules in adjacent states:** States adjacent to Wisconsin with moderate 8-hour ozone nonattainment areas are Illinois and Indiana. The Michigan nonattainment areas are of a lower non-attainment designation of either "Basic" or "Marginal".

<u>Wisconsin:</u> The proposed RACT rule contains emission limits and combustion tuning requirements. The emission limits apply to electric utility generating units and large industrial stationary sources. The combustion requirements apply to smaller units as well as the units subject to emission limits. The emission limits for large coal fired boilers is based on post combustion controls ranging from 35% to 90% reduction of uncontrolled emission levels at an estimated cost ranging from $1,000 to $2,500 per ton of NO_x removed. The emission limits for other industrial sources are based primarily on low NO_x combustion technology at an estimated cost from $500 to $2,500 per ton of NO_x removed.

<u>Illinois:</u> The state of Illinois has proposed a <u>statewide</u> RACT rule for industrial boilers and other sources with a potential to emit of 100 tons per year or greater. The Illinois proposed RACT emission limits are based on a cost-effectiveness ranging up to $2,500 per ton of NO_x removed. The resulting controls and emission limits are similar in stringency to the Wisconsin proposed emission limits and apply to similar

sources. Illinois EPA negotiated very stringent SO2 and NOx limitations with the utilities in Illinois that generate about 90% of the electric power in the state. The resulting emission limits for the Chicago area are more stringent than what the Department has proposed for NOx RACT in the Milwaukee area.

Indiana: Indiana is not proceeding with NOx RACT rule development at this time.

Michigan: The state of Michigan has made no determination regarding the need for developing RACT rules. A Michigan RACT rule is required only if attainment in the basic areas cannot be demonstrated by the state's SIP submittal deadline of June 2007.

Ohio: Ohio is developing NOx RACT rules for the Cleveland nonattainment area. Their proposal would affect emission units of 25 mmBtu/hr. Smaller units would be required to implement good combustion technology. Larger units could comply with over-fire air and low-NOx burners. Ohio is proposing to include electric generating units in their NOx RACT requirements.

8. **Summary of factual data and analytical methodologies:**

Department staff identified potentially affected units and source categories based on information contained in the air emissions inventory and source permits. A review of available emission control technologies and options was conducted based on available EPA resources, industry information, and other technical resources. General control assumptions and cost factors for each source category were used in evaluating appropriate emission limits and applicability. The proposed emission limitations were also compared to both existing and proposed RACT emission limits or NO_x emission control programs in other states.

9. **Analysis and supporting documents used to determine effect on small business or in preparation of economic impact report:**

The proposed rule is expected to affect only large industrial sources and therefore it is not anticipated to have an impact on small businesses.

10. **Effect on small business:**

The proposed rule is expected to affect only large industrial sources and therefore it is not anticipated to have an impact on small businesses.

11. **Agency contact person:**

Thomas Karman
Thomas.karman@dnr.state.wi.us
(608) 264-8856

12. **Place where comments are to be submitted and deadline for submission:**
Written comments may be submitted at the public hearings, by regular mail, fax or email to:

Tom Karman, AM/7
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Bureau of Air Management

PO Box 7921
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Written comments may also be submitted to the Department using the Wisconsin Administrative Rules Internet Web site at http://adminrules.wisconsin.gov.

Hearing dates and submission deadline are to be determined.

The consent of the Attorney General and the Revisor of Statutes will be requested for the incorporation by reference of new test methods in ch. NR 484.

SECTION 1. NR 428.04(2)(h)1. and 2. are amended to read:

NR 428.04(2)(h)1. 6.9 grams per brake horsepower-hour for a compression ignition unit with a maximum design power output of 1000 hp or greater.

2. 4.0 grams per brake horsepower-hour for a spark ignition unit with a maximum design power output of 1000 hp or greater.

SECTION 2. NR 428.05(3)(e)1. to 4. are amended to read:

NR 428.05(3)(e)1. 9.5 grams per brake horsepower-hour for rich-burn units.

2. 10.0 grams per brake horsepower-hour for lean-burn units.

3. 8.5 grams per brake horsepower-hour for distillate fuel oil-fired units.

4. 6.0 grams per brake horsepower-hour for dual-fuel units.

SECTION 3. NR 428 subch. IV to follow NR 428.11 is created to read:

SUBCHAPTER 1V

NO_X REASONABLY AVAILABLE CONTROL TECHNOLOGY REQUIREMENTS

NR 428.20 Applicability and purpose. (1) APPLICABILITY. The requirements of this subchapter apply to the owner or operator of a NO_X emissions unit which is in a source category

identified in s. NR 428.22 or 428.23 and which is located at a facility with a combined total potential to emit for all NO_X emissions units of 100 tons per year or more of NO_X and which is in the county of Kenosha, Milwaukee, Ozaukee, Racine, Sheboygan, Washington or Waukesha.

(2) PURPOSE. The purpose of this subchapter is to establish reasonably available control technology requirements for NO_X emissions units in the ozone nonattainment area consisting of the counties of Kenosha, Milwaukee, Ozaukee, Racine, Sheboygan, Washington and Waukesha to comply with sections 172(c) and 182(f) of the Act, (42 USC 7502(c) and 7511a(f)).

NR 428.21 Emissions unit exceptions. (1) LOW OPERATING UNIT. (a) Except as provided in par. (b) an emissions unit described in s. NR 428.20 is exempt from the emission limitations and the good combustion requirements of ss. NR 428.22 and 428.23 if the emissions unit's ozone season capacity utilization is less than the product of the source category ozone season potential utilization and the appropriate capacity factor in subd. 1. or 2.. The source category ozone season potential utilization is the capacity threshold or design output threshold for the unit's source category described in ss. NR 428.22 and 428.23. Where a capacity range is used as the threshold for a source category, the lower value of the range shall be used in determining ozone season potential utilization. The capacity factors are:

1. 0.10, except as specified in subd. 2.

2. 0.05 for an emissions unit described in s. NR 428.22(1)(g),(h) and (i).

(b) Once an emissions unit previously qualifying as a low operating unit exceeds the product in par. (a), the owner or operator shall meet the requirements of ss. NR 428.22 and 428.23 by May 1 of the following calendar year unless an extension is granted in writing by the department.

(2) OTHER REGULATED UNIT. An emissions unit which is subject to and meeting an emission limitation in s. NR 428.04 or 428.05(3) and which is subject to a federally enforceable permit condition limiting its potential to emit to less than 50 tons of NO_X per year is exempt from the emission limitations in s. NR 428.22.

NR 428.22 Emission limitation requirements. (1) EMISSION LIMITS. Except as provided in sub. (2), on or after May 1, 2009, no person may cause, allow or permit NO_X to be emitted in excess of the following emission limitations on a 30-day rolling average basis:

(a) *Boilers.* 1. For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 1,000 mmBtu per hour, one of the following, as applicable:

a. If tangential, wall, cyclone or fluidized bed-fired, 0.10 pound per mmBtu of heat input.

b. If arch-fired, 0.18 pound per mmBtu of heat input.

2. For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 500 mmBtu per hour and less than 1,000 mmBtu per hour, one of the following, as applicable:

a. If tangential-fired, 0.15 pound per mmBtu of heat input.

b. If wall-fired with a heat release rate equal to or greater than 0.12 mmBtu per hour per square foot of water-cooled surface, 0.17 pound per mmBtu of heat input.

c. If wall-fired with a heat release rate less than 0.12 mmBtu per hour per square foot of water-cooled surface, 0.15 pound per mmBtu of heat input.

d. If cylcone-fired, 0.15 pound per mmBtu of heat input.

e. If arch-fired, 0.18 pound per mmBtu of heat input.

g. If fluidized bed-fired, 0.10 pound per mmBtu of heat input.

3.For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 250 mmBtu per hour and less than 500 mmBtu per hour, one of the following, as applicable:

a. If tangential-fired, 0.15 pound per mmBtu of heat input.

b. If wall-fired with a heat release rate equal to or greater than 0.12 mmBtu per hour per square foot of water-cooled surface, 0.17 pound per mmBtu of heat input.

c. If wall-fired with a heat release rate less than 0.12 mmBtu per hour per square foot of water-cooled surface, 0.15 pound per mmBtu of heat input.

d. If cylcone-fired, 0.15 pound per mmBtu of heat input.

f. If arch-fired, 0.18 pound per mmBtu of heat input.

g. If fluidized bed-fired, 0.10 pound per mmBtu of heat input.

h. If stoker-fired boiler, 0.20 pound per mmBtu of heat input.

4. For a solid fuel-fired boiler with a maximum heat input capacity less than 250 mmBtu per hour, one of the following, as applicable:

a. If tangential-fired, 0.15 pound per mmBtu of heat input.

b. If wall-fired with a heat release rate equal to or greater than 0.12 mmBtu per hour per square foot of water-cooled surface, 0.17 pound per mmBtu of heat input.

c. If wall-fired with a heat release rate less than 0.12 mmBtu per hour per square foot of water-cooled surface, 0.15 pound per mmBtu of heat input.

d. If cylcone-fired, 0.15 pound per mmBtu of heat input.

e. If fluidized bed-fired, 0.10 pound per mmBtu of heat input.

f. If stoker-fired, 0.25 pound per mmBtu of heat input.

5. For a gaseous fuel-fired boiler with a maximum heat input capacity equal to or greater than 100 mmBtu per hour, 0.08 pound per mmBtu of heat input.

6. For a distillate fuel oil-fired boiler with a maximum heat input capacity equal to or greater than 100 mmBtu per hour, 0.10 pound per mmBtu of heat input.

7. For a residual fuel oil-fired boiler with a maximum heat input capacity equal to or greater than 60 mmBtu per hour, 0.15 pound per mmBtu of heat input.

(b) *Lime kilns.* For a lime kiln with a maximum heat input capacity equal to or greater than 50 mmBtu per hour, one of the following as applicable:

1. For a gaseous fuel-fired unit, 0.10 pound per mmBtu of heat input.

2. For a distillate oil-fired unit, 0.12 pound per mmBtu of heat input.

3. For a residual oil-fired unit, 0.15 pound per mmBtu of heat input.

4. For a coal-fired unit, 0.60 pound per mmBtu of heat input.

5. For a coke-fired unit, 0.70 pound per mmBtu of heat input.

(c) *Reheat, annealing or galvanizing furnaces.* For a reheat, annealing or galvanizing furnace with a maximum heat input capacity equal to or greater than 75 mmBtu per hour, 0.08 pounds per million Btu of heat input.

(d) *Glass furnaces.* For a glass manufacturing furnace with a maximum heat input capacity equal to or greater than 50 mmBtu per hour, 2.0 pounds per ton of produced glass.

(e) *Asphalt plants.* For an asphalt plant with a maximum heat input capacity equal to or greater than 65 mmBtu per hour, one of the following as applicable:

1. For a gaseous fuel-fired unit, 0.15 pound per million Btu of heat input.

2. For a distillate fuel oil-fired unit, 0.20 pound per million Btu of heat input.

3. For a residual fuel oil-fired or waste oil-fired unit, 0.27 pound per million Btu of heat input.

(f) *Process heaters.* For a process heater, including a dryer, oven or other external combustion unit which is not subject to another emission limit under this section, with a maximum heat input capacity equal to or greater than 50 mmBtu per hour, one of the following as applicable:

1. For a gaseous fuel-fired unit, 0.10 pound per mmBtu of heat input.

2. For a distillate oil-fired unit, 0.12 pound per mmBtu of heat input.

3. For a residual oil-fired unit, 0.18 pound per mmBtu of heat input.

(g) *Simple cycle combustion turbines*. For a simple cycle combustion turbine, one of the following exhaust outlet concentrations as applicable:

1. For a unit with a maximum design power output of 50 megawatts or greater, one of the following, as applicable:

a. If natural gas-fired, 9 parts per million dry volume, corrected to 15% O_2.

b. If distillate oil-fired, 25 parts per million dry volume, corrected to 15% O_2.

c. If biologically derived gaseous fuel-fired, 35 parts per million dry volume, corrected to 15% O_2.

2. For a unit with a maximum design power output less than 50 megawatts, one of the following as applicable:

a. If natural gas-fired, 25 parts per million dry volume, corrected to 15% O_2.

b. If distillate oil-fired, 65 parts per million dry volume, corrected to 15% O_2.

c. If biologically derived gaseous fuel-fired, 35 parts per million dry volume, corrected to 15% O_2.

(h) *Combined cycle combustion turbines.* For a combined cycle combustion turbine with a maximum design power output of 10 megawatt, 9 parts per million dry volume, corrected to15% O_2.

(i) *Reciprocating engines.* For a reciprocating engine with a maximum design power output of 250 horsepower, one of the following as applicable:

1. For a rich-burn spark ignition unit, 2.0 grams per brake horsepower-hour.

2. For a lean-burn spark ignition unit, 2.0 grams per brake horsepower-hour.

3. For a diesel fuel-fired compression unit, 2.6 grams per brake horsepower-hour.

4. For a dual fuel-fired compression unit, 2.0 grams per brake horsepower-hour.

(2) ELECTRIC UTILITY BOILER COMPLIANCE SCHEDULE. The owner or operator of an electric utility boiler subject to provisions of 40 CFR part 97 shall demonstrate compliance with the following interim emission limitations, as applicable, on a 30-day rolling average by May 1, 2009 and with the emission limitations in sub. (1)(a) on and after May 1, 2013:

(a) For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 1,000 mmBtu per hour one of the following as applicable:

1 If tangential, wall, cyclone or fluidized bed-fired, 0.15 pound per mmBtu of heat input.

2. If arch-fired, 0.18 pound per mmBtu of heat input.

(b) For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 500 mmBtu per hour and less than 1,000 mmBtu per hour one of the following as applicable:

1. If tangential-fired, 0.15 pound per mmBtu of heat input.

2. If wall-fired with a heat release rate equal to or greater than 0.12 mmBtu per hour per square foot of water-cooled surface, 0.20 pound per mmBtu of heat input.

3. If wall-fired with a heat release rate less than 0.12 mmBtu per hour per square foot of water-cooled surface, 0.20 pound per mmBtu of heat input.

4. If cylcone-fired, 0.20 pound per mmBtu of heat input.

5. If arch-fired, 0.18 pound per mmBtu of heat input.

6. If fluidized bed-fired, 0.10 pound per mmBtu of heat input.

NR. 428.23 GOOD COMBUSTION REQUIREMENTS. The owner or operator of an emissions unit at a facility identified under s. NR 428.20 which has a capacity to utilize 50 mmBtu/hr or greater of heat input shall meet the combustion requirements of this section for the emissions unit.

(1) COMBUSTION MEASUREMENT AND ADJUSTMENT. On and after May 1, 2009, an emissions unit shall be tuned and maintained to achieve a balance between combustion efficiency and emissions according to the following procedures:

(a) *Frequency.* 1. Except as specified in subd. 2., for an emissions unit subject to an emission limitation in s. NR 428.22, the combustion emissions shall be measured and combustion settings tuned during operation of the emissions unit on an hourly basis or on reaching steady state conditions after load changes of more than 15% of the emissions unit's capacity.

2. For an emissions unit subject to an emission limitation in s. NR 428.22(1)(f) or (i), the combustion emissions shall be measured and combustion settings tuned as follows:

a. Initially within the 90-day period prior to May 1, 2009.

b. After May 1, 2009, on a semi-annual basis with one tuning performed within the 60-day period prior to May 1 of each calendar year.

3. For an emissions unit not subject to tuning under subd. 1 or 2., the combustion emissions shall be measured and combustion settings tuned initially within the 90-day period prior to May 1, 2009 and then annually within the 60-day period prior to May 1 of each calendar year after 2009.

(b) *Methods.* 1. Combustion air leak checks and maintenance shall be conducted prior to initial tuning and then annually or more frequently as recommended by the manufacturer.

2. For an external combustion unit using a common windbox to distribute combustion air to multiple entry points of the combustion chamber, the individual airflows exiting the windbox shall be tested and balanced prior to tuning required in par. (a). Thereafter, the balance of the combustion air for the emissions unit shall be tested and adjusted every 2 years.

3. Measurements shall be taken of combustion flue gas concentrations of NO_X, CO and O_2, flue gas temperature, and unit load or fuel consumption rate prior to and after each adjustment of the combustion settings.

4. The adjustment of combustion settings shall be based on the measurements taken in subd. 3. and conducted to minimize overall NO_X emissions while maintaining or improving combustion efficiency according to the following criteria:

a. The NO_X emission rate shall be reduced through balancing and reducing combustion air flows in relation to fuel flow while maintaining safe and steady state combustion conditions.

b. An increase or decrease in anticipated mass emissions of NO_X, on an annual or ozone season basis, related to combustion efficiency, shall be used in identifying target combustion settings for the tuning process.

c. An increase or decrease in anticipated emissions of other pollutants of concern related to combustion efficiency may be used to demonstrate target combustion settings for the tuning process.

d. The balance of combustion settings and efficiency shall maintain compliance with all applicable regulatory requirements and may be based on maintaining or reducing emissions of particulates, sulfur dioxide or other pollutants of concern.

5. For an emissions unit subject to semi-annual or annual tuning under par. (a)2. or 3., the tuning shall be conducted for the primary fuel to be used in the operating period and at unit capacity load points for which the unit operated in the load ranges of 20 to 30%, 45 to 55%, 70 to 80%, and 90 to 100%.

(2) EQUIPMENT AND MEASUREMENT SPECIFICATIONS. The measurement of flue gas concentrations and combustion air flows taken to meet the requirements in sub. (1)(b) shall be conducted according to the specifications of this subsection.

(a) The combustion analyzer equipment used in measuring NO_X, CO and O_2 concentrations shall have an accuracy of 1 part per million and a span drift of less than 2%. The combustion analyzer test cells shall be replaced and the analyzer calibrated and maintained according to manufacturer's specifications.

(b) All flue air flow and flue gas concentration monitoring and sampling shall be taken in a location and manner consistent with the standard testing practices of s. NR 439.07 for obtaining representative measurements. The potential for air leakage into the flue system that may affect the measured flue gas concentrations shall be considered when determining sampling locations.

(3) TRAINING. The owner or operator of an emissions unit shall provide or ensure proper training of personnel responsible for meeting requirements of this section.

(4) COMPLIANCE DEMONSTRATION AND RECORDKEEPING. The owner or operator of an emissions unit shall demonstrate compliance by maintaining a record of each of the following:

(a) For each record required in pars. (b) to (g), the name of the personnel or third party entity responsible for performing the activity and the date and time.

(b) Combustion air leak checks including the location of leaks and corrective actions.

(c) Combustion air adjustments required under sub. (1)(b)2. including air flow sampling locations and measurement values.

(d) For each tuning required under sub. (1)(a), the fuel type and the measurements specified in sub. (1)(b)3. for NO_x, CO and O_2 flue gas concentrations, flue gas temperature, and unit load or fuel flow rate.

(e) An evaluation identifying flue gas concentrations and temperatures which address objectives in sub. (1)(b)4. for the potential range of unit loads and fuel flows

(f) A determination of the operating load ranges for tuning under sub. (1)(b)5.

(g) For all combustion monitoring equipment a log of the maintenance and calibration activities and a description of any malfunction including the time, duration, and corrective actions.

(5) ALTERNATIVE COMBUSTION REQUIREMENTS. (a) The owner or operator of an emissions unit subject to the requirements of s. NR 428.05(2) may comply with the requirements of this section by satisfying combustion optimization requirements in s. NR 428.05(2).

(b) The owner or operator of an emissions unit may use an alternative equivalent method for meeting the combustion tuning requirements of this section with written approval of the department.

NR 428.24 Demonstrating compliance with emission limitations. The owner or operator of an emissions unit shall determine the emissions unit's NO_x emissions and determine compliance with the emission limitations in s. NR 428.22 according to the following applicable methods:

(1) EMISSIONS MONITORING REQUIREMENTS. (a) *Installation and operation.* No later than April 1, 2009 or April 1 of the year an emissions unit first becomes subject to an emission limitation in s. NR. 428.22, the owner or operator of the emissions unit shall do the following:

1. Submit to the department in writing, a certification of the installation and operation of all monitoring systems or completion of initial emission performance tests required under par. (b).

2. Begin and continue to monitor, measure and record all data necessary to determine emissions in the units of the applicable emission limitation according to the methods of this section.

(b) *Monitoring systems and procedures.* 1. 'Part 75 continuous emissions monitoring.' The owner or operator of an affected unit as defined under s. NR 400.02(11), or an emissions unit subject to 40 CFR Part 97 shall meet the requirements of this subsection by installing and operating monitoring equipment and measuring and recording NO_x emissions data according to methods and specifications of 40 CFR part 75 and 40 CFR part 75, Appendices A to I, incorporated by reference in s. NR 484.04(27).

2. 'Continuous emissions monitoring.' Except as provided in subds. 1. and 3., the owner or operator of an emissions unit shall install and operate an emissions monitoring system and determine the hourly average NO_x emission rate according to this subdivision.

a. Install, calibrate, maintain and operate an NO_x diluent continuous emissions analyzer.

b. Install, calibrate, maintain and operate either an O_2 or CO_2 diluent continuous emissions analzyer for correcting all emissions data and heat rate values to the same basis as specified in subd. 6.b.

c. Operate the emissions monitoring system according to the requirements of s. NR 439.09(9), the applicable operating requirements of 40 CFR 60.13, the performance specifications in 40 CFR part 60, Appendix B, incorporated by reference in s. NR 484.04(21) and the quality assurance procedures of 40 CFR part 60, Appendix F, incorporated by reference in s. NR 484.04(21m).

d. For an emissions unit subject to an NO_x emission limit on a pound per million Btu basis, use the F-factor method and analysis of as fired fuel heat content according to methods in Method 19 of 40 CFR part 60, Appendix A, incorporated by reference in s. NR 484.04(16m).

3. 'Periodic emissions performance testing.' For an emissions unit subject to s. NR 428.22(1)(e),(f) or (i), the owner or operator of an emissions unit shall conduct an initial and, thereafter, a bi-annual emissions performance test to determine the emissions unit's maximum NO_x emission rate for each fuel fired in the emissions unit.

a. The emissions performance test shall be conducted according to one of the following methods as applicable: Method 7, 7A, 7B, 7C, 7D or 7E in 40 CFR part 60, Appendix A, incorporated by reference in s. NR 484.04(15m).

b. The NO_x emissions shall be measured during the initial performance test at unit capacity load points for which the unit operated in the load ranges of 20 to 30%, 45 to 55%, 70 to 80% and 90 to 100%. A performance test shall be performed within 90 days of completing an equipment modification or change in fuel which has the potential to increase the NO_x emission rate.

c. The emission rate used in demonstrating compliance for the emissions unit shall be the average NO_x emission value measured at the unit capacity load point demonstrating the highest emission rate over the unit capacity load points required in subd. 3.b. based on 3 test runs.

d. Subsequent bi-annual emission performance tests shall be conducted at the unit capacity load point identified in subd. 3.c. for the emission rate used in demonstrating compliance.

4. 'Continuous monitoring for an output based standard.' In addition to applicable monitoring and measuring requirements under subd. 2., the owner or operator of an emissions unit subject to an output emission limitation in NR 428.22(1)(d) shall do the following:

a. Install, maintain and operate monitoring equipment for measuring and recording the output on an hourly basis with 5% accuracy in units consistent with the applicable emission limitation.

b. Calculate on an hourly basis, the output based emission rate as the hourly mass of NO_x emissions determined according to subd. 5. divided by the emissions unit's total output for that hour.

5. 'Continuous monitoring of total heat input and mass emissions.' The owner or operator of an emissions unit required to measure total heat input or mass NO_x emissions for requirements of subd. 4., sub. (2)(c) and s. NR 428.26(1)(b) or (c) shall perform the applicable measurements according to following:

a. Except as provided in subd. 5.b., install, calibrate, maintain and operate a volumetric flue gas flow monitoring system meeting specifications in subd. 2.c. The hourly heat input shall be determined using the the F-factor and as fired fuel heat content according to Method 19 of 40 CFR part 60, Appendix A , incorporated by reference in s. NR 484.04(16m).

b. For a liquid or gaseous fuel fired system, the heat input may be determined using a fuel flow monitoring system capable of detemining the hourly flow with 5% accurancy. The total heat input shall then be calculated as the total fuel flow multiplied by the fuel heat content.

c. The heat content value for each fuel shall be based on a heat content analysis conducted according to Method 19 of 40 CFR part 60, Appendix A , incorporated by reference in s. NR 484.04(16m).

d. The mass of NO_x emissions shall be determined on an hourly basis by either multiplying the NO_x concentration by the flue gas flow rate corrected for diluent gas and moisture or, by multiplying the monitored hourly average emission rate in mass per mmBtu by the total heat input as determined under subd. 5.a. or b. The calculations of mass emissions are to be performed according to conversion procedures in 40 CFR part 75, Appendix F, incoroporated by reference in s. NR 484.04(26m).

6. 'General monitoring requirements.' Unless otherwise specified in this subsection, an owner or operator shall meet the following requirements:

a. All certification tests or emissions performance tests shall be performed according to procedures of s. NR 439.07.

b. The determination of emission rates, mass emissions and total heat input shall be calculated and corrected to the same basis for flue gas moisture and diluent gases according to Method 19 of 40 CFR part 60, Appendix A, incorporated by reference in s. NR 484.04 (16m) or 40 CFR part 75, Appendix F, incorporated by reference in s. NR 484.04(26m).

c. For emissions units with a common flue gas stack system, all sampling locations and apportionment of emissions to an individual emissions unit shall conform to applicable procedures and methods in 40 CFR part 75, Appendix F, incorporated by reference in s. NR 484.04(26m).

7. 'Malfunction and abatement.' An owner or operator of an emissions unit subject to the malfunction and abatement plan requirement of s. NR 439.11 shall include a malfunction plan for the emissions monitoring system and a monitoring and operating plan for continuing operation of the

emissions unit in a manner consistent with meeting all applicable emission limitations during any period when the monitoring system malfunctions or is inoperable other than for scheduled maintenance.

8. 'Alternate emissions monitoring.' Except for an emissions unit subject to subd. 1., an owner or operator may use, with written approval of the department, continuous parametric monitoring according to performance specifications in 40 CFR part 75, Appendix E, incorporated by reference in s. NR 484.04(27) or an equivalent alternative to any requirement of this subsection.

(2) COMPILATION OF EMISSIONS. An owner or operator shall compile the measured emissions data in units consistent with the units of the applicable emission limitation according to the following applicable calculation and tabulation methods for purposes of demonstrating compliance:

(a) *Continuous emissions monitoring*. When measuring emissions according to requirements in sub. (1)(b)1. or 2.:

1. The average emission rate shall be the average of the hourly average emissions obtained from the continuous emissions monitoring system for the hours the emissions unit operated during the averaging period. The calculation is as follows:

$$E_A = \left(\frac{1}{n}\right)\sum_{j=1}^{n} E_{H,j} \quad \text{Equation 1}$$

where:

E_A is the average emission rate for the compliance period in units consistent with units of the applicable emission limit.

$E_{H,j}$ is the hourly average emission rate for each hour, j, for which the emissions unit is operating during the compliance period in units consistent with units of the applicable emission limit.

n is the total number of hours the emissions unit operated during the compliance period.

2. The 30-day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30-day rolling average emission rate (E_A) shall be calculated and recorded at the end of each day.

(b) *Emissions performance testing*. When measuring emissions according to performance testing requirements of sub. (1)(b)3., the 30-day rolling average emission rate or concentration shall be the emissions determined in sub. (1)(b)3.c. and d. for the most recent performance test.

(c) *Multiple fuel-fired emissions units*. When measuring emissions for an emissions unit firing multiple fuels, compliance shall be determined according to one of the following methods:

1. The unit's emissions shall be monitored and compiled according to applicable methods in par. (a) or (b) for each individual fuel and compliance demonstrated with the emission limitation for each fuel.

2. The unit's emissions and a multiple fuel emission limit shall be determined on a total heat input fuel weighted basis according to equation 2. A fuel representing less than 1% of the unit's annual fuel consumption on a heat input basis may be excluded in determining the multiple fuel emission limit.

$$E_{HIWieghted} = \frac{\sum_{f=1}^{n} E_f HI_f}{\sum_{f=1}^{n} HI_f} \qquad \text{Equation 2}$$

where:

$E_{HIWeighted}$ is the heat input weighted multiple fuel emission rate or emission limitation for the compliance period in units consistent with the units of the emission limitation

E_f is the emission rate or emission limit for fuel F during the compliance period in units consistent with the units of the emission limitation

HI_f is the total heat input for fuel F during the compliance period

n is the number of different fuels used during the compliance period

(d) *Total heat input and mass emissions*. When measuring hourly heat input or mass of NO_x emissions according to sub. (1)(b)5., the totals over a period of time shall be compiled according to the following procedures:

1. The total hourly heat input shall be summed for the hours the emissions unit operated during the applicable period of time according to equation 3.

$$HI_{total} = \sum_{h=1}^{n} HI_h \quad \text{Equation 3}$$

where:

HI_{total} is the total heat input by fuel over the period of time

HI_{jh} is the heat input by fuel for hour h

n is the number of hours over which the specific fuel was burned

2. The total hourly mass of NO_x emissions shall be summed for the hours the emissions unit operated during the applicable period of time according to equation 4.

$$NO_x\ Mass_{total} = \sum_{h=1}^{n} Mass_h \qquad \text{Equation 4}$$

where:

$NO_x\ Mass_{total}$ is the total mass of NO_x emissions over the period of time

$Mass_h$ is the mass of NO_x emissions for hour h

n is the number of hours the emissions unit is operating during the specified period of time

NR 428.25 Recordkeeping and reporting. (1) EMISSION LIMITATIONS. The owner or operator of an emissions unit subject to an emission limitation in s. NR 428.22 shall meet the recordkeeping and reporting requirements of this subsection.

(a) *Recordkeeping.* In addition to the recordkeeping requirements of ss. NR 439.04(1) and (2) and 439.05, the owner or operator shall maintain records of all of the following:

1. The applicable emission limit and calculated heat input weighted emission limit for an emissions unit demonstrating compliance for multiple fuels.

2. The 30-day rolling average emission rate on a daily basis determined according to s. NR 428.24.

3. The total monthly heat input for each fuel or the output, as applicable, in units consistent with the units of the applicable emission limitation.

4. The emissions unit's annual and ozone season capacity utilization in units consistent with the units of the applicable emission limitation.

5. For the emissions monitoring system required in s. NR 428.24(1)(b) on an annual and ozone season basis, records of performed maintenance, hours of malfunction and necessary repairs, and the percent of hours the monitoring system operated during the emissions unit's operating hours.

(b) *Reporting.* In the reports to the department required under s. NR 439.03(1)(b), the owner or operator shall submit the following information:

1. A certification of compliance with the applicable emission limitation in s. NR 428.22 or identification of the periods of non-compliance, with a quantification of the excess emission rate and the excess mass emissions.

2. For each calendar month, the highest 30-day rolling average emission rate. The emissions data shall be reported in the units of the applicable emission limitation.

3. The emissions unit's annual and ozone season total operating hours, capacity utilization, and the percent operation of any required continuous emissions or combustion monitoring systems during the hours the emissions unit was operating.

(2) COMBUSTION REQUIREMENTS. The owner or operator of an emissions unit subject to the combustion requirements in s. NR 428.23 shall meet the following recordkeeping requirements:

(a) Compile and maintain a record of emissions unit tuning activities, combustion parameters and maintenance activities and a record of the combustions monitoring equipment operation and maintenance as identified in s. NR 428.23(4)

(b) The records described in par. (a) shall be maintained onsite for a period of 3 years after which the data is generated.

(3) LOW OPERATING UNIT. The owner or operator of an emissions unit claiming a low operating unit exception under s. NR 428.21(1), shall maintain a record of the unit's applicable fuel heat input or output, the unit's total capacity utilization on an ozone season and annual basis for each calendar year and calculations demonstrating qualification for the exception.

(4) OTHER REGULATED UNIT. The owner or operator of an emissions unit claiming a regulated emissions unit exception under s. NR 428.21(2), shall maintain a record of all performance tests, calculations, assumptions and methods used to determine the emissions unit's potential emissions.

NR 428.26 Alternative compliance methods and approaches. (1) EMISSIONS AVERAGING. The owner or operator of an emissions unit may demonstrate compliance with an NO_x emission limitation in s. NR 428.22 by participating in an emissions rate averaging program according to the general provisions of par. (a) and either the specifications for facility wide averaging in par. (b) or the multi-facility averaging in par. (c).

(a) *General provisions.* 1. 'Participating units.' a. The participation of an emissions unit in an emissions averaging program shall be designated for a full calendar year. Inividual emissions units may not be withdrawn from an averaging program, during a year, unless each emissions unit in the averaging program meets its applicable emission limit in s. NR 428.22.

b. If an emissions unit at a facility participates in an averaging program, all similar units at the facility shall be included in the averaging program. Similar units at a facility are those which serve a

similar process or purpose and which are described by the same general source category under s. NR 428.22 without regard to fuel type or unit size threshold.

c. An emissions unit for which the department has approved an alternative emission limit or compliance schedule under sub. (3) may not participate in an emissions averaging program under this subsection.

2. 'Monitoring requirement.' The owner or operator of an emissions unit participating in an emissions averaging program shall monitor all necessary NO_x emissions according to requirements of s. NR 428.24(1)(b)1. or 2. The total heat input and NO_x mass emissions shall be monitored and measured according to s. NR 428.24(1)(b)5. and tablulated according to s. NR 428.24(2)(d).

3. 'New units'. An emissions unit which begins operation on or after the effective date of this rule… [revisor insert date] may not participate in an emissions averaging program under this subsection.

4. 'Emission reductions.' For purposes of this subsection only emission reductions which go beyond all state and federal requirements are considered excess emission reductions.

(b) *Facility averaging*. An owner or operator may average emissions from emissions units at one facility by complying with the following procedures for demonstrating compliance on an annual and ozone season basis with an aggregate NO_x emission limit and mass cap:

1. 'Notification.' The owner or operator shall submit to the department a notification of an NO_x emissions averaging program by October 1 of the year prior to the emissions averaging year. The notification shall include the following information:

a. The participating emissions units.

b. The owner or operator of each emissions unit.

c. For a unit subject to s. NR 428.22, the applicable emission limitation.

d. For a participating emissions unit not subject to s. NR 428.22, the average emission rate by fuel type over the unit's normal operating range determined according to methods of s. NR 428.24(1)(b)3.a.

and b. The tested average emission rate may be adjusted based on a heat input weighted average of the emissions unit's annual percent operation at different load points in the previous calendar year.

e. For averaging programs effective on or after January 1, 2013, for each emissions unit, the annual and ozone season heat input for 2000 to 2005, and the annual and ozone season average of the 3 years of highest annual heat input for 2000 to 2005.

f. For averaging programs effective on or after January 1, 2013, an annual and ozone season NO_x mass emission cap in aggregate for the emissions units in the averaging program. The mass caps shall be the summation of the products for each emissions unit of the emission limitation in subd. 1.c. or the average emission rate in subd. 1.d. and the 3-year average annual or ozone season heat input. In the case of an emission limitation expressed on an output basis, the applicable quantified output shall replace heat input for purposes of this calculation. The mass emission cap shall be calculated as follows:

$$MC = \sum_{i=1}^{n} \left[\sum_{j=1}^{k} E_j HI_j \right]_i \qquad \text{Equation 5}$$

where:

MC is either the annual mass cap or the ozone season mass cap in tons of NO_x for all units participating in the averaging program

E_j is the applicable emission limitation for fuel j submitted in subd. 1.c. or the average emission rate in subd. 1.d.

HI_j is either the average annual or ozone season heat input for fuel j, submitted in 1.e., for the 3 years of highest heat input from 2000 to 2005

k is the number of fuels fired by a unit either during the year or during the ozone season

n is the number of units participating in the averaging program

2. 'Implementation.' The department shall review the proposed averaging program provided in the

notification and unless the department, within 30 days of recieving the proposed averaging program, requests additional information or revisions to the program, the owner or operator shall comply with the submitted emissions averaging program.

3. 'Compliance demonstration.' The owner or operator of emissions units participating in the averaging program shall submit a compliance report containing the following information by March 1 of the calendar year following the averaging program year:

a. The annual and ozone season actual heat input by fuel type for each emissions unit in the averaging program.

b. The annual and ozone season actual NO_x mass emissions for each emissions unit.

c. The annual and ozone season actual average NO_x emission rate for each emissions unit calculated as follows:

$$ER_{avg} = \frac{NO_x \text{ Mass}}{\sum_{j=1}^{n} HI_j} \qquad \text{Equation 6}$$

where:

ER_{avg} is the annual or ozone season average emission rate for each emissions unit

NO_x Mass is the total NO_x mass emissions for the averaging period

HI_j is the heat input for fuel type j for the averaging period

n is the number of fuels fired during the averaging period

d. The annual and ozone season actual NO_x mass emissions and heat input in aggregate for all emissions units.

e. The annual and ozone season actual aggregate NO_x emission rate for all emissions units. This emission rate is the summation of the total mass of NO_x emissions for all emissions units divided by the total heat input for all emissions units and is calculated as follows:

$$ER_{aggr} = \frac{\sum_{u=1}^{n} NO_x \ Mass_u}{\sum_{u=1}^{n} HI_u} \qquad \text{Equation 7}$$

where:

ER_{aggr} is the emission rate in aggregate for all emissions units on an annual or ozone season basis

NO_x $Mass_u$ is the total NO_x mass emissions for emissions unit u, for the averaging period

HI_u is the total heat input for each emissions unit u, for the averaging period

n is the number of emissions units participating in averaging

f. The annual and ozone season aggregate emission limitation for all emissions units. These emission limitations are the summation of the product of each unit's actual heat input and emission limitation by fuel type divided by the summation of the actual heat input for all emissions units. The aggregate emission limitations shall be calculated as follows:

$$EL_{aggr} = \frac{\sum_{u=1}^{n} \left(\sum_{f=1}^{j} HI_f \, EL_f \right)}{\sum_{u=1}^{n} HI_u} \qquad \text{Equation 8}$$

where:

EL_{aggr} is the aggregate emission limit for all emissions units on an annual or ozone season basis

HI_f is the heat input for fuel f, for unit u

EL_f is the emission limit for fuel f, for unit u

HI_u is the total heat input for emissions unit u, for the averaging period

n is the number of emissions units participating in averaging

f is the number of fuels for unit u

g. Compliance on an annual and ozone season basis is demonstrated if the aggregate emission rate required in subd. 3.e. is less than the aggregate emission limit required in subd. 3.f., and the NO_x mass emissions required in subd. 3.b. is less than the mass cap required in subd. 1.f.

4. For an emissions unit subject to emission limitations expressed in units other than heat input, the emission limitation shall be converted to a heat input basis. All required calculations shall be on a common basis with necessary conversions performed according with methods in 40 CFR part 60, appendices A or B, incorporated by reference in s. NR 484.04(13) and (21).

5. 'Mass cap exceedence.' If the total NOx emissions from the emissions units in the averaging program exceed either the annual or ozone season emission caps determined in subd. 1.f., the owner or operator shall achieve additional NO_x reductions to compensate for the excess emissions within 3 calendar years after the averaging year with the exceedence.

(c) *Multi-facility average.* An owner or operator may average emissions from emissions units at multiple facilities by complying with the following procedures for demonstrating compliance on an annual and ozone season basis with an aggregate NO_x emission limitation:

1. 'Notification.' The owner or operator shall submit to the department a notification of an NO_x emissions averaging program by October 1 of the year prior to the emissions averaging year. The notification shall include the following information:

a. The participating emissions units.

b. The owner or operator of each emissions unit.

c. The applicable emission limitation in s. NR 428.22 for each emissions unit.

d. The projected heat input, capacity utilization, NO_x emission rate and total NO_x mass emissions for each emissions unit on an annual and ozone season basis.

e. The projected heat input, capacity utilization, NO_x emission rate and total NO_x mass emissions in aggregate for all emissions units participating in the averaging program.

2. 'Implementation.' The department shall review the proposed averaging program provided in the

notification and unless the department, within 30 days of receiving the proposed averaging program, requests additional information or revisions to the program, the owner or operator shall comply with the submitted emissions averaging program.

3. 'Public notice.' a. The owner or operator proposing to average emissions units at multiple facilities shall provide public notice 60 days prior to the calendar year of the averaging program in newspapers of general circulation for the areas of the emissions units.

b. The public notice shall describe the proposed averaging program, the participating emissions units and how to obtain a copy of the averaging program information required in subd. 1.

c. In addition to the information required in subd. 1., the averaging program information provided to the public upon request shall indicate whether any of the emissions units identified in the proposed averaging program participated in prior averaging programs under this subsection and whether that participation resulted in a violation of the emission limits.

4. 'Compliance demonstration.' The owner or operator participating in an averaging program shall submit a compliance report containing the following information by March 1 of the calendar year following the averaging program year:

a. The annual and ozone season actual heat input for each emissions unit.

b. The annual and ozone season actual NO_x mass emissions for each emissions unit.

c. The annual and ozone season actual average NO_x emission rate for each emissions unit calculated using Equation 6 in par. (b)3.c.

d. The annual and ozone season actual NO_x mass emissions and heat input in aggregate for all emissions units.

e. The annual and ozone season aggregate NO_x emission rate for all emissions units calculated using Equation 7 in par. (b)3.e.

f. The annual and ozone season aggregate emission limitation for all emissions units. These emission limitations are the summation of the product of the each unit's actual heat input and emission

limitation divided by the summed actual heat input for all emissions units less an averaging program environmental benefit factor. The aggregate emission limitations are calculated as follows:

$$EL_{aggr} = \frac{\sum_{u=1}^{n} HI_u EL_u}{\sum_{u=1}^{n} HI_u} x(1 - EBF) \qquad \text{Equation 9}$$

where:

EL_{aggr} is the aggregate emission limit in aggregrate for all emissions units on an annual or ozone season basis

HI_u is the heat input for each emissions unit, u, for the specified period of time

EL_u is the emission limit for each emissions unit, u. For emission limitations in units other than heat input, the emission limitations shall be converted to a heat input basis according to sub. (b)4.

EBF is the environmental benefit factor. For averaging programs effective on or after January 1, 2013, the EBF is 10% for the annual emission limit and 10% for the ozone season emission limit. Prior to this date the EBF is 0%.

g. A demonstration of compliance on an annual and ozone season basis consisting of the aggregrate emission rates under subd. 4.e. compared to the aggregate emission limitations calculated in subd. 4.f.

(d) *Violations and penalties*. 1. All emissions units participating in an emissions averaging program are considered out of compliance if emissions exceed any of the averaging program emission limitations on either an annual or ozone season basis.

2. Each emissions unit participating in the averaging program shall be considered in violation for each day of non-compliance until corrective action is taken to achieve compliance.

3. Unless the department grants an electric or steam utility reliability waiver under s. NR 428.28 to the emissions units exceeding the applicable aggregate average emission limitation, the department shall require the owners or operators of the emissions units in the program to achieve reductions equivalent to the amount of the exceedence. The additional emission reductions shall be achieved within the subsequent 3 years on an annual or ozone season basis, consistent with the period of the exceedence.

4. All owners or operators of emissions units considered out of compliance with an averaging program emission limitation are liable for each violation and subject to enforcement and penalty provisions under ss. 285.83 and 285.87, Stats.

5. The parameters required in the notice under par. (c) 1.d. shall consitute annual and ozone season alternative compliance limits for each unit participating in a multi-facility averaging program under par. (c). If compliance is demonstrated under par. (c)4.g., all emissions units in the averaging program shall be deemed to be in compliance with the alternative compliance limits.

(2) CAIR EMISSIONS UNITS. The owner or operator of an emissions unit which is subject to the emission reduction requirements of the clean air interstate rule (CAIR) under 40 CFR part 97 may demonstrate that the NO_x emission reductions achieved by the emissions unit in complying with the CAIR requirements constitute compliance with the NO_x RACT emission limitation requirements of this subchapter.

(3) ALTERNATIVE RACT REQUIREMENT. (a) The owner or operator of an emissions unit may request that the department establish an alternative emission limitation or alternative compliance deadline to the requirements in s. NR 428.22 if the owner or operator demonstrates that it is economically or technically infeasible to meet the requirement.

(b) The owner or operator of the emissions unit shall submit the request with the demonstration for an alternative RACT requirement by the later of May 1, 2008 or by May 1 following the calendar year in which an emissions unit first becomes subject to an emission limitation in s. NR 428.22.

(c) Any request for an alternative RACT requirement made under this subsection shall be subject to the requirements and procedures of s. NR 436.05.

NR 428.27 Green tier. (1) An owner or operator of an emissions unit subject to s. NR 428.22 may enter into a contract under s. 299.83, Stats., to fulfill the requirements of this subchapter by developing and executing an emissions reduction plan achieving superior environmental performance. The emissions reduction plan may include either of the following:

(a) An alternate compliance schedule that achieves greater NO_x emissions reductions than would otherwise be achieved under this subchapter, or achieves emissions reductions of other pollutants in addition to NO_x reductions.

(b) An alternate compliance approach that achieves overall greater NO_x emission reductions and environmental benefits through NO_x emission reductions at an alternate emissions unit.

(2) Any emissions reduction plan shall be consistent with reasonable further progress for ozone attainment under 42 USC 7502(c)(2) and may not impede attainment of the ozone air quality standard.

(3) Any contract negotiated under s. 299.83, Stats., may include reductions in recordkeeping, reporting or other administrative requirements related to environmental regulations as appropriate as an incentive for the activities described in sub. (1). The amount of flexibility provided shall be proportional to the environmental benefits provided by the participant.

(4) This subsection clarifies how s. 299.83, Stats., may apply in meeting requirements of s. NR 428.22, but nothing in this subchapter limits or supersedes the department's authority under s. 299.83, Stats.

NR 428.28 Electric and steam utility reliability waiver. The owner or operator of an emissions unit used for purposes of electric or steam utility generation and subject to an emission limitation in s. NR

428.22 may request that the department grant a waiver from meeting the emission limitation for a specific period of time based on the following criteria and procedures:

(1) The waiver request is due to the utility's need to maintain a supply of electricity or steam for space heating or cooling to non-interruptible customers.

(2) A waiver request may only be based on an unavoidable or unforeseeable event including:

(a) A major electric supply event affecting the utility.

(b) A major fuel supply disruption affecting the utility.

(c) A disruption in the operation of a generating unit or pollution control equipment.

(3) The owner or operator of a major utility shall submit a written request for a waiver that provides information sufficient to demonstrate to the department’s satisfaction that granting the waiver is warranted. The request shall include the following:

(a) The duration of the conditions warranting the waiver.

(b) The specific measures taken to mitigate emissions during the duration for which the waiver is requested.

(c) The reasons why the utility was unable to achieve compliance with the emission requirement.

(4) The department may grant a waiver under this section if, in consultation with the public service commission, the department determines that the owner or operator's failure to meet a requirement under s. NR 428.22 is consistent with criteria of sub. (2).

(5) Within 60 days after the receipt of a complete request, the department shall publish a public notice of the receipt of the waiver request and the department’s preliminary determination to approve, conditionally approve, or deny the the request. The department shall provide an opportunity for public comments on the request and the department's preliminary determination. The department shall hold a public hearing on the request if a hearing is requested by a person affected by the waiver request.

(6) Following the public comment period, the department shall notify the applicant in writing of the final determination to approve, conditionally approve or deny the waiver request.

SECTION 4. NR 484.04(13) is amended to read:

	CFR Appendix Referenced	Title	Incorporated by Reference For
(13)	40 CFR part 60 Appendix A	Test Methods	NR 400.02(131) NR 428.26(1)(b)4. NR 439 NR 460 to 469

SECTION 5. NR 484.04(15m) and (16m) are created to read:

	CFR Appendix Referenced	Title	Incorporated by Reference For
(15m)	40 CFR part 60 Appendix A, Method 7, 7A, 7B, 7C, 7D and 7E	Determination of nitrogen oxide emissions from stationary sources	NR 428.24(1)(b)3.a.
(16m)	40 CFR part 60 Appendix A, Method 19	Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates	NR 428.24(1)(b)2.d., 5.a. and c. and 6.b.

SECTION 6. NR 484.04(21m) is amended to read:

	CFR Appendix Referenced	Title	Incorporated by Reference For
(21m)	40 CFR part 60 Appendix F	Quality Assurance Procedures	NR 428.24(1)(b)2.c. NR 466.10(2)

SECTION 7. NR 484.04(26m)(cm) is created to read:

	CFR Appendix Referenced	Title	Incorporated by Reference For
(26m)(cm)	40 CFR part 75 Appendix E	Optional NO Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units	NR 428.24(1)(b)8.

SECTION 8. NR 484.04(26m)(d) and (27) are amended to read:

CFR Appendix Referenced	Title	Incorporated by Reference For
(26m)(d) 40 CFR part 75 Appendix F	Conversion Procedures	NR 428.24(1)(b)5.d. and 6.b. and c. NR 446.04(3) NR 446.09(1)(a)
(27) 40 CFR part 75 Appendices A to I		NR 428 NR 439 NR 428.24(1)(b)1.

SECTION 9. EFFECTIVE DATE. This rule shall take effect on the first day of the month following publication in the Wisconsin administrative register as provided in s. 227.22 (2) (intro.), Stats.

SECTION 10. BOARD ADOPTION. This rule was approved and adopted by the State of Wisconsin Natural Resources Board on _____.

Dated at Madison, Wisconsin _____.

STATE OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES

By_____
Scott Hassett, Secretary

(SEAL)

Wisconsin Department of Administration
Division of Executive Budget and Finance
DOA-2048 (R10/2000)

Fiscal Estimate — 2003 Session

☒ Original ☐ Updated	LRB Number	Amendment Number if Applicable
☐ Corrected ☐ Supplemental	Bill Number	Administrative Rule Number AM-17-05

Subject

RACT rules in s. NR 428.20 to 428.28 for major sources of NOx emissions in the ozone non-attainment counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan.

Fiscal Effect

State: ☐ No State Fiscal Effect

Check columns below only if bill makes a direct appropriation or affects a sum sufficient appropriation.

☐ Increase Existing Appropriation ☐ Increase Existing Revenues
☐ Decrease Existing Appropriation ☒ Decrease Existing Revenues
☐ Create New Appropriation

☒ Increase Costs — May be possible to absorb within agency's budget.
☒ Yes ☐ No

☐ Decrease Costs

Local: ☒ No Local Government Costs

1. ☐ Increase Costs ☐ Permissive ☐ Mandatory
2. ☐ Decrease Costs ☐ Permissive ☐ Mandatory
3. ☐ Increase Revenues ☐ Permissive ☐ Mandatory
4. ☐ Decrease Revenues ☐ Permissive ☐ Mandatory
5. Types of Local Governmental Units Affected:
☐ Towns ☐ Villages ☐ Cities
☐ Counties ☐ Others _____
☐ School Districts ☐ WTCS Districts

Fund Sources Affected

☐ GPR ☐ FED ☒ PRO ☐ PRS ☐ SEG ☐ SEG-S

Affected Chapter 20 Appropriations

20.370 2(bg) & (bh)

Assumptions Used in Arriving at Fiscal Estimate

The Department is proposing this rule package to meet Clean Air Act requirements for implementing a reasonably available control program for NO_x emissions from major sources capable of emitting 100 tons per year or more of nitrogen oxides in the moderate ozone non-attainment counties. The affected emission units include electric utility generating units and industrial combustion emission units. The majority of emission units are subject to emission limitations and good combustion requirements with a set of smaller emission units only subject to good combustion requirements.

1. Impact on the Department:

The annual emissions fees paid to the department are affected by the reduction in NO_x emissions. The estimated reduction related to RACT controls achieved by 2013 is approximately 19,000 tons of NOx annually below 2004 emission levels. The related reduction in emission fees or reduced revenue to the department is approximately $400,000 to $450,000 per year based on the current emission fee schedule.

2. Impact to government affected facilities:

The UW-Milwaukee facility has three boilers used for heating and cooling purposes. The units already have combustion modifications in place sufficient to meet rule emission limitation requirements. The facility may have to implement recordkeeping and additional monitoring to meet good combustion requirements at a minimum net cost increase.

3. Impact on non-government affected facilities

These cost estimates are based on general cost assumptions and factors applicable to each of the source categories. The proposed rule requires the most significant reductions from thirteen coal-fired electric utility boilers. The primary cost of reduction for electric generating units is due to the anticipated installation and operation of major

(Continued on page 2)

Long-Range Fiscal Implications

Prepared By:	Telephone No.	Agency
Joseph Polasek	266-2794	Department of Natural Resources
Authorized Signature	**Telephone No.**	**Date (mm/dd/ccyy)**
	266-2794	

Wisconsin Department of Administration
Division of Executive Budget and Finance
DOA-2048 (R10/2000)

Fiscal Estimate — 2003 Session

☒ Original	☐ Updated	LRB Number	Amendment Number if Applicable
☐ Corrected	☐ Supplemental	Bill Number	Administrative Rule Number AM-17-05

Subject

NOx RACT rules in s. NR 428.20 to 428.28 for major sources in the ozone non-attainment counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan.

(Assumptions Used in Arriving at Fiscal Estimate , page 2)

post combustion pollution control equipment. These costs are expected to be in the range of $40 to $60 million per year with an estimated cost-effectiveness between the affected utility units ranging from $1,000 to $2,200 per ton of removed NO_x. The total cost represents approximately 0.2 cents per kWh. Approximately one half of this annual cost can be attributed to controls already in place in meeting other requirements. It should be noted that these NO_x reductions may overlap to some degree with other NO_x reductions required in the CAIR and BART proposed rule packages, but the estimated fiscal cost is not additive between the proposed rules affecting the electric utility sector.

Additionally, the proposed emission limits may affect approximately 44 industrial emission units. The estimated total cost for these sources is subject to some uncertainty for several reasons: a) sources may not be subject to the emission limits due to being below the potential to emit; b) some sources appear to not have significant operation during the ozone season and therefore are exempt from the emission limits, and c) some of the affected units are expected to already be operating below the RACT emission limits. The cost of control for the industrial sources is expected to be in the range $2,000,000 to $3,000,000 per year or up to approximately $2,500 per ton of removed NO_x. It is estimated that approximately 60 additional emission units may be subject to combustion requirements only. The cost of meeting combustion requirements is expected to be minimal due to fuel savings.

Wisconsin Department of Administration
Division of Executive Budget and Finance
DOA-2047 (R10/2000)

Fiscal Estimate Worksheet — 2003 Session

Detailed Estimate of Annual Fiscal Effect

☒ Original	☐ Updated	LRB Number	Amendment Number if Applicable
☐ Corrected	☐ Supplemental	Bill Number	Administrative Rule Number AM-17-05

Subject

NOx RACT rules in s. NR 428.20 to 428.28 for major sources in the ozone non-attainment counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan.

One-time Costs or Revenue Impacts for State and/or Local Government (do not include in annualized fiscal effect):

Annualized Costs:	Annualized Fiscal Impact on State Funds from:	
A. State Costs by Category	Increased Costs	Decreased Costs
State Operations — Salaries and Fringes	$	$ -
(FTE Position Changes)	(FTE)	(- FTE)
State Operations — Other Costs		-
Local Assistance		-
Aids to Individuals or Organizations		-
Total State Costs by Category	$	$ -
B. State Costs by Source of Funds	Increased Costs	Decreased Costs
GPR	$	$ -
FED		-
PRO/PRS		-
SEG/SEG-S		-
State Revenues — Complete this only when proposal will increase or decrease state revenues (e.g., tax increase, decrease in license fee, etc.)	Increased Revenue	Decreased Revenue
GPR Taxes	$	$ -
GPR Earned		-
FED		-
PRO/PRS		- 400,000
SEG/SEG-S		
Total State Revenues	$	$ -400,000

Net Annualized Fiscal Impact

	State	Local
Net Change in Costs	$ 0	$ 0
Net Change in Revenues	$ -400,000	$ 0

Prepared By: Joe Polasek	Telephone No. 266-2794	Agency Department of Natural Resources
Authorized Signature	Telephone No. 266-2794	Date (mm/dd/ccyy)

CORRESPONDENCE/MEMORANDUM

State of Wisconsin

DATE: January 3, 2007

TO: Members of the Natural Resources Board

FROM: Scott Hassett, Secretary

SUBJECT: Reasonably Available Control Technology (RACT) program for major sources of nitrogen oxides (NO_x) in the moderate ozone nonattainment area and miscellaneous non-substantive corrections to current NR 428 requirements.

Introduction

In June 2004, the US EPA designated ten Wisconsin counties as nonattainment for the 8-hour ozone ambient air quality standard. The counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan are designated as "moderate" ozone nonattainment and the counties of Manitowoc, Kewaunee, and Door as "basic." The designation triggered federal Clean Air Act requirements for adopting rules to reduce oxides of nitrogen (NO_x) and volatile organic compound emissions sufficiently to demonstrate attainment of the ozone standard by 2009 in basic areas and 2010 in moderate areas.

The federal Clean Air Act requires implementation of "reasonably available control technology" (RACT) for major stationary sources of NOx and volatile organic compounds (VOC) in the moderate ozone nonattainment area by May 1, 2009. The Department is proposing this rule package to meet the RACT requirement for major sources of NO_x emissions. The Department previously adopted RACT rules for VOC to address the old 1-hour ozone standard. Under the 1-hour, the State had a waiver for implementing NOx RACT. No such waiver exists for the 8-hour standard. Therefore, the Department must proceed with developing NOx RACT rules.

To develop the proposed rules, the Department used the flexibility that EPA allows in creating RACT rules. However, these proposed rules do not exceed federal Clean Air Act requirements.

Potential NO_x emission requirements for the basic nonattainment areas are not addressed in this rule package, since NO_x RACT is required in basic areas only if attainment cannot be demonstrated by the 2009 ozone season.

One issue associated with RACT rule development warrants additional attention. EPA allows a state to determine if the Clean Air Interstate Rule (CAIR) satisfies NOx RACT requirements for major utility coal-fired boilers subject to CAIR. This is often referred to as the "CAIR = RACT" determination. This provision is based on EPA's assessment that the CAIR program, on a national basis, achieves greater reductions than the total reductions from a surrogate RACT program only in the nonattainment areas. Department legal staff has identified significant legal issues associated with EPA's assessment. In particular, RACT and CAIR are separate requirements in the Clean Air Act and implementation of CAIR cannot satisfy the RACT requirement. DNR legal staff indicates that both programs must be implemented.

1. Why is this rule being proposed?

The Department is proposing this rule to comply with the requirements of the federal Clean Air Act to implement a NOx RACT program for major sources in the moderate 8-hour ozone

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nonattainment areas. The resulting NO_x emission reductions will directly contribute to achieving attainment of the 8-hour ozone and PM2.5 standards and will aid in meeting future haze requirements.

Additionally, the Department is proposing the rule to make a non-substantive change to NR 428. NR 428.05(3)(e) currently sets forth emission limitations for reciprocating engines. The units for the emission limit currently read grams per brake-horsepower (gr /br-hp). The units are corrected in this rule package to read grams per brake-horsepower hour (gr / br-hp-hr). This proposed change in the current language is consistent with the NR 428 rule package adopted by the Board in 2000.

2. Summary of the rule

The proposed rule establishes NO_x RACT emission requirements for major sources in the moderate ozone nonattainment areas. The emission requirements apply to individual stationary combustion units at major sources and must be met by May 1, 2009.

The emission requirements consist of NO_x emission limitations and combustion tuning requirements which apply on a year-round basis. The emission limitations are established by source categories with an emission unit size threshold based on available control technologies and cost-effectiveness. Combustion tuning requirements apply to the emission units subject to emission limitations, but also generally to smaller emission units. The rule contains exemptions from both RACT requirements for certain types of emission units demonstrating low operating levels during the ozone season. An additional exemption recognizes that certain smaller emission units are already well controlled under existing NR 428 provisions and no further action is needed in meeting the RACT emission limit. Attachment A provides the technical assessment that supports the Department's proposed rule.

a. General Applicability

The proposed rule affects facilities with the potential to emit of 100 tons or more of NO_x per year in the moderate ozone nonattainment areas, but the emission limits apply to individual emission units, such as a boiler or furnace, at the affected facilities. It is possible that an emission unit contributing to a major source's potential to emit may not be subject to a RACT requirement. Likewise, an emission unit identified by a RACT source category, but at a facility with a potential to emit less than 100 tons per year, will not be subject to a RACT requirement.

b. Categorical Emission Limits

The proposed rule establishes NO_x emission rate limits by source category applicable to emission unit operating above threshold levels during the ozone season. The proposed source categories, operating levels, and emission limitations are presented in Table 1. The emission limits contained in the proposed rule are a 30-day rolling average requirements applicable on a year-round basis. A unit subject to an emission limitation must demonstrate compliance on an individual basis by May 1, 2009.

Table 1. Proposed NO_x RACT Categorical Emission Limits[1].

Source Category	Capacity Threshold	NO_x Emission Limitation (30 day rolling average)
Solid Fuel-Fired Boiler	=> 1000 mmBtu/hr	Tangential-fired.....0.10 lbs/mmBtu Wall-fired.....0.10 lbs/mmBtu Cyclone-fired .....0.10 lbs/mmBtu Fluidized bed-fired.....0.10 lbs/mmBtu Arch-fired..... 0.18 lbs/mmbtu
	=> 500 mmBtu/hr and < 1000 mmBtu/hr	Tangential-fired.....0.15 lbs/mmBtu Wall-fired (low heat release).....0.15 lbs/mmBtu Wall-fired (high heat release).....0.17 lbs/mmBtu Cyclone-fired .....0.15 lbs/mmBtu Fluidized bed-fired.....0.10 lbs/mmBtu Arch-fired..... 0.18 lbs/mmBtu
	=> 250 mmBtu/hr and < 500 mmBtu/hr	Tangential-fired.....0.15 lbs/mmBtu Wall-fired (low heat release).....0.15 lbs/mmBtu Wall-fired (high heat release).....0.17 lbs/mmBtu Cyclone-fired .....0.15 lbs/mmBtu Fluidized bed-fired.....0.10 lbs/mmBtu Arch-fired..... 0.18 lbs/mmBtu Stoker-fired.....0.20 lbs/mmBtu
	< 250 mmBtu/hr	Tangential-fired.....0.15 lbs/mmBtu Wall-fired (low heat release).....0.15 lbs/mmBtu Wall-fired (high heat release).....0.17 lbs/mmBtu Cyclone-fired .....0.15 lbs/mmBtu Fluidized bed-fired.....0.10 lbs/mmBtu Arch-fired..... 0.18 lbs/mmBtu Stoker-fired.....0.25 lbs/mmBtu
Gaseous or Liquid Fuel-Fired Boiler	=> 100 mmBtu/hr..... => 60 mmBtu/hr.....	Gaseous fuel.....0.08 lbs/mmBtu Distillate oil.....0.10 lbs/mmBtu Residual or waste oil.....0.15 lbs/mmBtu
Lime Kiln (manufacturing)	=> 50 mmbtu/hr	Gaseous fuel.....0.10 lbs/mmBtu Distillate oil.....0.12 lbs/mmBtu Residual oil.....0.15 lbs/mmBtu Coal.....0.60 lbs/mmBtu Coke.....0.70 lbs/mmBtu
Glass Furnace	=> 50 mmbtu/hr	2.0 lbs/ton of glass
Metal Reheat, Galvanizing, and Annealing Furnace	=> 75 mmbtu/hr	0.08 lbs/mmBtu
Asphalt Plants	=> 65 mmbtu/hr	Natural gas.....0.15 lbs/mmBtu Distillate oil.....0.20 lbs/mmBtu Residual or waste oil.....0.27 lbs/mmBtu
Process Heating Units	=> 50 mmBtu/hr	Natural gas.....0.10 lbs/mmBtu Distillate oil.....0.12 lbs/mmBtu Residual or waste oil.....0.18 lbs/mmBtu

Simple Cycle Combustion Turbine	=> 50 MW	Natural gas.....9 ppmdv @ 15% O_2 Distillate oil.....25 ppmdv @ 15% O_2 Biologically derived fuel..... 35 ppmdv @ 15% O_2
	< 50 MW	Natural gas.....25 ppmdv @ 15% O_2 Distillate oil.....65 ppmdv @ 15% O_2 Biologically derived fuel..... 35 ppmdv @ 15% O_2
Combined Cycle Turbine	10 Megawatt	9 ppmdv @ 15% O_2
Reciprocating Engine	250 horsepower	Rich-burn units.....2.0 gr/bhp-hr Lean-burn units.....2.0 gr/bhp-hr Distillate-fuel units.....2.6 gr/bhp-hr Natural Gas / Dual fuel.....2.0 gr/bhp-hr

1) The compliance deadline for most sources is May 1, 2009. However, electric generating units have interim emission limits and extended compliance time frames. See Table 2.

1. Implemented on an annual basis

The proposed rule implements the RACT requirements on an annual basis. This is the default approach for RACT as reflected in the current EPA 8-hour ozone Phase II Implementation Rule (70 FR 71611). Controls implemented for ozone purposes are cost-effective to operate year-round and yield continual air quality benefits related to fine-particles, haze, acid rain, and eutrophication of lakes.

2. 30-day rolling average emission limit

The 30-day rolling averaging time is a short term, rate-based approach to ensure full benefit of the installed control equipment. In this way, emissions are continuously controlled in the event conditions are conducive to forming ozone. This approach allows averaging of the typical variations in controlled emission levels from a single unit.

3. Emission unit exceptions

Emission units which operate at very low levels during the ozone season are exempt from RACT requirements. The rule also exempts units with low emission rates from installing additional controls to meet the RACT emission limits.

4. Compliance monitoring and demonstration

The proposed rule requires most sources subject to emission limitations to demonstrate compliance using continuous emissions monitoring. For electric utility (EGU) sources this monitoring is based on 40 CFR part 75 methods and for industrial source monitoring is based on 40 CFR part 60 methods. For a few source categories with low variability in operations or emission rates, compliance is demonstrated by periodic stack testing. The proposed emission monitoring requirements are consistent with existing state and EPA programs. The rule will also allow a source to petition for approval of an alternative monitoring method.

5. Electric utility coal-fired boiler phased compliance schedule.

For electric utility coal-fired boilers the rule sets a phased compliance schedule with interim emission limits for May 1, 2009 and final RACT emission limits by May 1, 2013. The purpose of the phased compliance schedule is to allow the electric utilities the necessary time to install post combustion controls while maintaining a reliable electric supply. Some control technologies, like selective catalytic reduction equipment, can take up to two years to install for an individual project. This is compounded by the fact that

utilities are subject to limited installation windows which further restrict the installation schedule. On this basis, multiple installations cannot be fully accomplished on all electric utility boilers within the moderate nonattainment area by 2009. The phased approach is also consistent with operating generating units on a system-wide basis and utilization of a multi-facility averaging program.

The schedule of phased limitations is provided in Table 2. The interim emission limits for 2009 is based on implementation of full combustion modifications and a limited number of selective non-catalytic reduction installations. In this manner, the proposed rule sets forth a RACT level of NO_x control across electric utility boilers achieved on a schedule the Department has found to be expeditious as practicable. Attachment B summarizes expected emissions from electric utility coal fired boilers.

Table 2. Compliance Schedule for Electric Utility Coal-Fired Boilers

Compliance Date	**Emission Limits (lbs/mmbtu)**	
	Coal-fired Boilers > 1000 mmbtu/hr	**Coal-fired Boilers >500 and <1000 mmbtu/hr**
May 1, 2009	wall fired = 0.15 tangential fired = 0.15 cyclone = 0.15 arch fired = 0.18	wall fired = 0.20 tangential fired = 0.15 cyclone = 0.20 arch fired = 0.18
May 1, 2013	wall fired = 0.10 tangential fired = 0.10 cyclone = 0.10 arch fired = 0.18	wall fired = 0.17 tangential fired = 0.15 cyclone = 0.15 arch fired = 0.18

6. Alternative compliance methods.

The proposed RACT rule provides several compliance options.

1) Emissions from one or more units subject to a RACT emission limitation may be averaged with other similar units at an industrial or small utility facility. Under this approach all similar units at the facility must be included in the averaging program. This is to eliminate a potential shift in generation/ production to unit not subject to the RACT requirements.

Emissions averaging applies the current applicable emission limit of each unit on a heat input weighted basis to determine an average facility or system emission limit. The EPA requires that averaging programs like the system averaging in the proposed rule have an additional emission reduction applied to the facility or system emission limit as an environmental benefit in lieu of the provided flexibility. (See *Improving Air Quality with Economic Incentive Programs*, EPA-452/R-01-001, Jan. 2001.) Under facility averaging the proposed environmental benefit is the implementation of an annual and ozone season mass cap.

2) Emissions units may participate in an emission averaging program across multiple units and facilities. Each unit can only participate in one type of averaging program on an annual basis (facility or system-wide). The proposed

environmental benefit is the EPA default of 10% reduction in the emission rate on an annual and ozone season basis.

3) An individual source may request an alternative emission limitation or compliance schedule, with a determination made on a case-by-case basis by the Department. An alternative emission limit may be the result of an engineering assessment that demonstrates RACT controls are not economically or technically feasible for that unit. Any determination of an alternative limit or schedule must also account for a unit's ability to participate in either a facility or system-wide emissions averaging program.

7. Utility reliability waiver

The proposed rule contains a provision that allows an electric or steam utility to request a waiver from an applicable emission limit for a period of time due to electric reliability issues. This provision acknowledges that an electric utility has non-interruptible customers and that events may occur which result in an increase in emissions. A similar waiver is available for facilities selling steam to facilities for heating and cooling purposes in which human health may be impacted. Facilities generating steam for process and manufacturing purposes are not eligible for the waiver.

c. Combustion Tuning Requirements

The proposed rule contains good combustion requirements for emission units to perform monitoring and combustion tuning. The tuning requirement is integral to RACT and the emission limits in several ways. First, the balancing and staging of the combustion process is a primary first step in reducing NOx emissions. The tuning process and associated combustion monitoring ensures continual operation in this manner. Second, the potential reduction in fuel consumption by improving combustion efficiency will reduce the overall amount of NO_x mass emissions and other pollutants. Third, sources may elect to utilize combustion monitoring as part of an alternative continuous emissions NO_x compliance monitoring method or as a check interim to NO_x stack testing.

3. Impact to Existing Policy

This proposal is consistent with existing state statutory policy for ozone rules under s. 285.11(6), Wis. Stats., to revise and implement state implementation plans for the purpose of prevention, abatement and control of air pollution in Wisconsin.

4. Has the Board dealt with these issues before?

Most recently the NRB adopted ch. NR 428 in 2000 for regulation of NO_x emissions from stationary sources in the state. The regulations were formulated to meet rate-of-progress and attainment requirements for the 1-Hour Ozone Attainment Demonstration in Southeastern Wisconsin. The rule established performance standards for existing electric utility and larger industrial sources in the area now designated as moderate under the 8-Hour ozone standard. The sources subject to NR 428 requirements are also subject to the proposed RACT rules. In some cases, meeting the NR 428 limits exempts units based on lowering their potential to emit below 100 tons per year.

5. Who will be affected by the proposed rule? How will they be affected?

The proposed rule affects emission units at major source facilities and which have applicable emission limits or good combustion requirements specified in the rule. In the moderate nonattainment areas the affected emission units include electric utility generating units, industrial boilers, combustion turbines, glass and steel furnaces, asphalt plants, process heaters, and reciprocating engines. Refer to Attachment A for a summary of anticipated general control levels and range of cost-effectiveness represented by rule requirements.

The affected electric utility generating units consist primarily of 13 large coal fired boilers. The proposed rule is likely to result in significant post-combustion controls achieving 50% to 90% reduction from uncontrolled emissions for most of these units, at a cost effectiveness ranging from $1,000 to $2,200 per ton of controlled NO_x emissions. The rule also affects 3 coal-fired boilers which are smaller than typical electric generating units, but which are used for steam utility services. These boilers will require less intensive post-combustion controls, approximately a 50% reduction, at a cost-effectiveness of $2,500 per ton. All of these coal-fired boilers are eligible to participate in multi-facility trading allowing electric utilities maximum flexibility in meeting RACT requirements.

The remaining source categories are primarily gaseous and oil-fired combustion processes. The prevalent method of control applied to these types of emission units is combustion modification consisting of over-fire air and low NO_x burners. The Department expects combustion modifications to achieve a 30% to 60% reduction across the different source categories burning gas and oil. The one exception is very large reciprocating engines, where it appears cost-effective controls may achieve an 80% reduction in emissions. The analysis of the rule identifies that up to 44 gaseous or oil fired emission units may have to take additional action to meet proposed RACT emission limits of the rule. This results in an estimated NO_x reduction of 65% from 2002 emission levels at a cost effectiveness ranging from $500 to $2,500 per ton.

The RACT rule also requires good combustion practices, mainly combustion tuning, for all 50 mmBtu/hr units emissions units. Good combustion requirements may affect up to an additional 60 gaseous and oil fired emission units which are smaller than those addressed by emission limit requirements. This requirement is expected to yield approximately 40 tons of NOx reductions for these units from 5% to 35% at a net savings or a minimal cost.

6. What are other states doing?

States near Wisconsin with 8-hour ozone nonattainment areas are Illinois, Indiana, Michigan and Ohio. Illinois, Indiana and Ohio also have moderate non-attainment areas. All of the Michigan nonattainment areas are of a lower non-attainment designation of either "basic" or "marginal".

<u>Illinois:</u> The state of Illinois has proposed a <u>statewide</u> RACT rule for industrial boilers and other sources with a potential to emit of 100 tons per year or greater. The Illinois proposed RACT emission limits are based on a cost-effectiveness ranging up to $2,500 per ton of NO_x removed. The resulting controls and emission limits are similar in stringency to the Wisconsin proposed emission limits and apply to similar sources. Illinois EPA negotiated very stringent SO2 and NOx limitations with the utilities in Illinois that generate about 90% of the electric power in the state. The resulting emission limits for the Chicago area are more stringent than what the Department has proposed for NOx RACT in the Milwaukee area.

Indiana: Indiana is not proceeding with NOx RACT rule development at this time.

Michigan: The state of Michigan has made no determination regarding the need for developing RACT rules. A Michigan RACT rule is required only if attainment in the basic areas cannot be demonstrated by the state's SIP submittal deadline of June 2007.

Ohio: Ohio is developing NOx RACT rules for the Cleveland nonattainment area. Their proposal would affect emission units of 25 mmBtu/hr. Smaller units would be required to implement good combustion technology. Larger units could comply with over-fire air and low-NOx burners. Ohio is proposing to include electric generating units in their NOx RACT requirements.

7. Information on environmental analysis

An environmental analysis of the impact of the proposed rule revisions is not needed as these changes are considered to be a Type III action under s. NR 150.03(3), Wis. Adm. Code. A Type III action is one that normally does not have the potential to cause significant environmental effects, normally does not significantly affect energy usage and normally does not involve unresolved conflicts in the use of available resources.

8. Initial regulatory flexibility analysis

There are no emission or performance requirements or compliance and reporting requirements proposed for small businesses and as such are not anticipated to directly affect small businesses. The proposed RACT rules are applicable to major industrial entities and electric utility facilities.

Small business may experience electricity rate impacts related to RACT requirements for the electric generation sector. The cost of controls is estimated to be less than 1-3% of current electricity rates.

Attachment A.

DATE: January 4, 2007

TO: Larry Bruss

FROM: Tom Karman

SUBJECT: Technical Basis for RACT Determinations

This document provides the technical basis for evaluating Reasonably Available Control Technology (RACT) for NO_X emission units in Southeastern Wisconsin.

Definition of RACT

The EPA defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." (44 FR 53762, September 17, 1979.)

Evaluating RACT

In the mid-1990's, NO_x RACT programs were implemented by other states to meet requirements under 1-hour ozone non-attainment designations. However, because NO_x control technologies and costs have changed, I found it necessary to perform an up-to-date evaluation of RACT. Although the majority of emission source categories are similar across RACT affected areas, other determinations may not address issues specific to emission units found in Wisconsin.

According to the EPA definition, the determination of RACT for the proposed rule is based on evaluating two primary criteria:

- A review of available control technologies and applicable emission reductions for each type of emissions unit.
- The cost-effectiveness, typically expressed in terms of dollars per ton of NO_x, of applying the control technologies.

I performed an evaluation of these two criteria following general approaches and methods established by EPA in the series of Alternative Control Technology documents for NO_x source categories. These documents formed the primary basis of 1990 vintage RACT evaluations. However, I updated the information on control technology and costs based on more recent EPA documents, equipment vendor information, or actual installations and quotes. In some cases, I obtained the cost-effectiveness directly from reference resources utilizing the same or similar methodologies. All cost information is presented in 2000 or later dollars. I adjusted costs from historic documents based on the consumer price index.

The first step in the RACT evaluation process is to identify control technologies applicable to general emission source categories. I applied the control efficiencies of the technologies to typical uncontrolled emission rates to yield a controlled emission rate. In many cases a

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combination of combustion modifications and post-combustion controls may be technically feasible.

Unless specifically stated, I assumed that the reported control efficiencies were based on long-term averages of control technology performance. When determining the appropriate emission limit for a control measure using a 30 day rolling average fro compliance, it is necessary to consider the potential variation in the control efficiency. To account for this variation, I applied a compliance margin factor in calculating the proposed emission limits. The general categories of control technologies and compliance margins are summarized in Table A1. The definitions of acronyms used for the control technologies can be found at the end of the memo.

Table A1. General NOx Controls Applied in the RACT Evaluation.

Category	Technology	Control Efficiency	Compliance Margin
Combustion Modifications	LEA – Tuning	5 – 35%	NA
	Combustion air staging: OFA, FGR	25% - 50	Gaseous & oil fired – 10%
	LNB	50 – 70%	Solid fuel fired – 15%
	Steam/water Injection	70% - 90%	10%
Post Combustion	SNCR	35% - 60	20%
	SCR	75% - 90%	25%

To determine cost-effectiveness, I estimated the annual cost for each control technology and divided it by the amount of controlled NO_x emissions. The annual control cost consists of the total capital and installation costs annualized over the life of the equipment plus annual operating costs. I calculated the total emission reductions from the uncontrolled emission rate assuming capacity utilization ranges indicated by the EPA methods. However, I also evaluated cost-effectiveness at lower utilization capacities where units may operate over a wider range. For certain large source categories or emission units, including the coal boilers, I estimated the average cost based on the actual operation of existing Wisconsin units.

The determination of RACT is an iterative process where the evaluations of technology and cost-effectiveness further define sub-categories of emission units and applicable RACT requirements. For particular source categories the cost-effectiveness will define unit sizes and operational levels or capacity factors differentiating RACT requirements. I proposed the emission limits to reflect these considerations.

Cost-effectiveness Basis for RACT

In a 1994 memo, EPA indicated that controls costing in the range of $160 to $1,300 per ton with a 30 to 50% reduction of NO_x emissions should be considered RACT. In the recent 8-hour ozone Phase II Implementation rule, EPA once again stated these criteria were applicable in evaluating RACT. However there are several considerations that indicate other levels of cost-effectiveness may be more appropriate in the current determination of RACT.

- Converting the $1,300 per ton cost-effectiveness from the 1994 memo to 2005 dollars, using the consumer price index, results in a cost-effectiveness of $2,000 per ton.

- The cost range referenced in EPA's 1994 memo was based on an analysis of controls available at that time. Since then, availability, control efficiencies, and cost of control

equipment have changed. EPA's original evaluation of what was considered a "deep" level of control, SCR installations at 80 to 90% reduction, is now typical of NO_x control installations for large sources.

- Higher levels of NO_x control cost are indicated as reasonable by other NO_x RACT programs. Staff from the Northeast Ozone Transport Commission region indicates the average cost-effectiveness for their already established NO_x RACT programs ranged upwards to $3,500 per ton. Also, other states currently in the process of developing RACT emission limits are considering controls at cost-effective levels higher than that presented in EPA's 1994 memo. For example, the state of Illinois used a cost-effectiveness of $2,500 per ton as a guideline in proposing RACT emission limits for industrial source categories. A recent determination of RACT for the Charleston, South Carolina identified RACT reductions up to $3,500 per ton. And in 1990, the California Air Resources Board determined that a range of $2,000 to $10,000 for cost-effectiveness as the average rate for installation of NO_x controls.

- EPA in their determination of NOx controls for the NOx SIP call determined $2,000 per ton to be "highly cost-effective".

For the evaluation, I assumed an upper limit of approximately $2,500 per ton of NOx removed for proposing NOx RACT emission limits.

Recommended RACT Control Levels

Based on the methodology outlined above, I propose RACT controls for Southeastern Wisconsin that include emission limits for large sources and combustion tuning for all sources larger than 50 mmBtu/hr.

The emission limits are listed in detail for each source category in Table A2 along with the associated controls from the analysis, the references for the assumed control, cost factors in each case and a few comments. The application of control assumptions and proposed RACT limits for existing coal fired boilers in Wisconsin are addressed in a separate section below.

I found combustion tuning to be an integral first step in reducing NOx emission for all for emission units equal to or greater than 50 mmBtu/hr in fuel consumption capability. Across the source categories the costs of combustion tuning for these units is largely offset by fuel savings. Below this level, combustion tuning may also beneficial, but there was less information for all source categories (7).

Table A2. Summary of RACT Source Categories and RACT Controls

Source Category		Base Emission Rate (lbs/ mmBtu)	Control Technology and Efficiency	Control Ref.	RACT Emission Limit (lbs/ mmBtu/hr)	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Wall-fired boilers	> 1000 mmBtu/hr	0.46	SCR – 86%	1, 2, 3	0.10	1,300 – 1,600	2, 5	
	500 - 1000 mmBtu/hr – HHR	0.47	LNB – 40% +OFA- 25% +SNCR - 35%	2, 4	0.17	1,300 – 1,400	2	SNCR control adjusted for HHR.
	500 - 1000 mmBtu/hr – LHH	0.46	LNB – 40% +OFA- 25% +SNCR - 40%	2, 4	0.15	1,300 – 1,400	2	
	< 500 mmBtu - HHR	0.47	LNB – 40% +OFA- 25% +SNCR - 35%	2, 4	0.17	1,800 – 2,100	6	SNCR control adjusted for HHR.
	< 500 mmBtu - LHR	0.46	LNB – 40% +OFA- 25% +SNCR - 40%	2, 4	0.15	1,800 – 2,100	6	Cost is for 250 - 100 mmBtu/hr boilers @ 50% c.f.
Tangential-fired boilers	> 1000 mmBtu/hr	0.46	SCR – 86%	1, 2, 3	0.10	1,200 – 1,900	2	
	< 1000 mmBtu/hr	0.46	LNB – 40% +OFA- 25% +SNCR - 40%	2, 4	0.15	1,500 – 2,100	2,6	Cost is for 1000 - 100 mmBtu/hr boilers @ 50% c.f.
Cyclone-fired boilers	> 1000 mmBtu/hr	0.79	OFA – 50% +SCR – 89%	1, 2, 3	0.10	700 -1,200	2	assumed PC boiler OFA cost
	< 1000 mmBtu/hr	0.86	OFA – 50% +SCR – 75%	1, 2, 3	0.15	1,700 – 2,100	2, 5	Low cost represents Edge 3 from ref. 2. High cost is derived from ref. 6 for 100mmBtu/hr boiler @ 50% c.f.
Arch-fired boilers	all capacity sizes	0.24	Tertiary Air – 20%	3	0.18	1,200 – 1,500	2	Reported average emission rate
Fluidized bed boilers	all capacity sizes	0.15	SNCR – 50 to 60%	4,6,7	0.10		6	
Stoker fired boilers	≥ 250 mmbtu/hr	0.50	OFA – 25% + SNCR – 50 to 60%	4,6,7	0.20	<2,500	6	
	< 250 mmbtu/hr	0.50	SNCR – 50 to 60%	4,6,7	0.25	<2,500	6	

Table A2. Summary of RACT Source Categories and RACT Controls (continued)

Source Category		Base Emission Rate (lbs/mmBtu)	Control Technology and Efficiency	Control Ref.	RACT Emission Limit (lbs/ mmBtu/hr)	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Gas fired boilers	> 150	0.22	LNB/OFA/GR – 80%	6	0.05	700 – 2,100	6	Cost range for 80% & 25% C.F., respectively
	> 100 – 150 mmBtu/hr	0.22	LNB/OFA/GR – 60%	6	0.08	700 – 2,200	6	Cost range for 80% & 25% C.F., respectively
Distillate oil fired boilers	> 100 mmBtu/hr	0.21	LNB/OFA/GR – 50%	6	0.10	< 2,300	6	Cost for 100 mmBtu/hr boiler @ 50% C.F.
Residual oil fired boilers	> 50 mmBtu/hr	0.38	LNB/OFA/GR – 50%	6	0.15	< 1,600		Cost for 50 mmBtu/hr boiler @ 50% C.F.
Gas fired process heater	> 50 mmBtu/hr	0.26	LNB – 60%	7	0.10	<2,300	6	Cost for 50 mmBtu/hr @ 25% C.F.
Distillate oil process heater	> 50 mmBtu/hr	0.32	LNB/GR – 70%	7	0.12	<2,500	6	Cost for 50 mmBtu/hr @ 25% C.F.
Residual oil process heater	> 50 mmBtu/hr	0.54	LNB/GR – 70%	7	0.18	< 1,500	6	Cost for 50 mmBtu/hr @ 25% C.F.
Metal Furnaces	> 100 mmBtu/hr	0.22	LNB/OFA/GR – 60%	6	0.08	700 – 2,200	6	Assume cost for NG Boilers

Table A2. Summary of RACT Source Categories and RACT Controls (continued)

Source Category		Base Emission Rate (gr/bhp-hr)	Control Technology and Efficiency	Control Ref.	RACT Emission Limit (gr/bhp-hr)	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Reciprocating Engines > 250 hp	Rich-burn	16.4	LEC – 90%	9	2.0	< 2,500	9	Cost for 250 hp unit @ 50% C.F.
	Lean-burn	18.6	LEC – 90%	9	2.0	< 2,500	9	Cost for 250 hp unit @ 50% C.F.
	Distillate compression	13	SCR	9	2.6	< 2,500	9, 7	Cost for 250 hp unit @ 50% C.F.
	Dual fuel compression	10.7	LEC – 90%	9	2.0	< 2,500	9	Cost for 250 hp unit @ 50% C.F.

Source Category		Base Emission Rate (ppm @ 15% O2)	Control Technology and Efficiency	Control Ref.	RACT Emission Limit (ppm @ 15% O2)	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Simple CTs > 50 MW	Distillate Oil	200	SCR - 90%+	7	25	< 2,500	7	Interpolated cost-effectiveness for 25 and 100 MW units @ 25% C.F.
	Natural Gas	99 – 430	DLN - 90%+	7	25	< 1,300	7	Cost-effectiveness for 25 MW unit @ 25% CF
Simple CTs < 50 MW	Distillate Oil	200	Steam/Water Injection – 80%	7	65	< 2,100	7	Cost-effectiveness for 25 MW unit @ 25% C.F.
	Natural Gas	99 – 430	DLN - 90%+	7	25	< 1,300	7	
Combined Cycle CT > 10 MW	Distillate Oil	200	Steam/Water Inj. + SCR 90%+	7	9	< 2,500	7	Interpolated cost-effectiveness for 5 and 25 MW units @ 90% C.F.
	Natural Gas	99 – 430	DLN 90%+	7, 10	9	< 2,500	7	
Biogas fired combustion turbines	Biogas	25 – 35	Inherently low emission combustion	10	35			

Table A2. Summary of RACT Source Categories and RACT Controls (continued)

Source Category		Base Emission Rate	Control Technology and Efficiency	Control Ref.	RACT Emission Limit	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Glass Furnace	> 50 mmBtu/hr	10 lbs/ton of glass	Oxy-firing	7	2.0 lbs/ ton of glass	<2,500	7	Oxy-firing during rebuild can pay for itself.
Lime Kiln > 50 mmBtu/hr	Natural Gas	U.D.	LNB	10	0.10	700 – 2,200	7	- Assume same cost as boilers for NG, DO, RO.
	distillate oil	U.D.		10	0.12 lbs/mmbtu	< 2,300	7	
	residual oil	U.D.		10	0.15 lbs/mmbtu	< 1,600	7	
	coal	U.D.	mid-kiln firing	10	0.60 lbs/mmbtu	< 1,000	7	-Controls based on WDNR BACT analysis. -Cost based on cement plants
	coke	U.D.		11	0.70 lbs/mmbtu		7	
Asphalt Plants > 65 mmbtu/hr	Natural Gas	0.26	LNB – 50%	10	0.15 lbs/mmbtu	<2,300	7	assume same as process heater costs
	distillate oil	0.32	LNB – 50%	10	0.20 lbs/mmbtu	<2,500	7	
	residual oil	0.54	LNB – 50%	10	0.27 lbs/mmbtu	< 1,500	7	

U.D - undetermined

Impact to Wisconsin Sources

I compiled an estimate of Wisconsin sources potentially affected by the RACT requirements along with the associated emission reduction and cost-effectiveness. The results are summarized by general control level in Table A3 and by specific source category in Table A4.

The affected sources are identified and impacts calculated based on the 2002 air emissions inventory. I calculated the emission reductions by applying the proposed RACT emission limit or representative control efficiency. For asphalt plants, reciprocating engines, process heater, and metal furnaces, source categories units are screened by comparing reported emissions to the potential emissions of an uncontrolled source.

The RACT emission limitations represent a 30% to 90% reduction (from uncontrolled emission rates) with an estimated cost-effectiveness ranging from $500 to $2,500 per ton of reduction. The emission limitations represent an estimated reduction of approximately 29,940 tons per year of NOx from 2002 emission levels. An assumed 15% reduction from combustion tuning results in about a 41 tons per year NO_x reduction.

Table A3. Proposed RACT Control Levels and Estimated Cost Effectiveness.

Control Categories*	2002 NO_x Emissions	Reduction from uncontrolled emission rates**	Estimated Cost-Effectiveness ($/ton)***	Estimated NOx Reduction from 2002 Emissions
Coal fired boilers => 500 mmBtu/hr	30,000 tpy (13 units)	50 - 90% Comb. Mods, SNCR, SCR	1,000 – 2,200	28,800 tpy (72% reduction)
Coal fired boilers < 500 mmbtu/hr	277 tpy (3 units)	50% Comb. Mods, SNCR	2,000 – 2,500	140 tpy (50% reduction)
Other Source Categories (gas and oil fired)[b]	1,600 tpy (43 units)	30 - 80% Comb. Mods., SCR	500 – 2,500	1,000 tpy (64% reduction)
Units subject to only combustion tuning	280 tpy (60 units)	5 – 35% Combustion Tuning	0 - 500	41 tpy (15% reduction)

* Solid fuel boilers greater than 500 mmbtu/hr are large electric utility coal-fired boilers. Solid fuel boilers smaller than 500 mmbtu/hr include smaller electric utility and industrial sized solid fuel boilers. "Other Source Categories" include gas and oil boilers, combustion turbines, furnaces, asphalt plants, lime kilns, reciprocating engines, and heating processes.

** Percent reductions are from an uncontrolled basis. Combustion modifications = overfire air and low NO_x burners. SCR = Selective catalytic reduction. SNCR = Selective non-catalytic reduction.

*** The presented cost-effectiveness represents the calculated "average" cost of reduction from an uncontrolled or initial emissions level as defined for each source category.

Note: The estimate of affected units and emissions is based on emission units estimated to be in a RACT source category. The actual number of affected units in the "Others Source Categories" is expected to be lower due to units being at facilities with a PTE < 100 TPY or being classified as low operating units.

Table A4. Estimated Impact of RACT applied to Wisconsin Sources.

RACT Source Category	Sources in RACT Category			Impact of RACT Requirements			Proposed RACT Control	
	No. of Units (1)	2002 NOx Emissions (tons)	Emission Intensity (tons/unit)	Est. No. of units not meeting RACT (2)	Est. NOx reduction from 2002 emissions (tons)	Percent reduction from 2002 emissions	RACT Control Technologies	Estimated Control Cost from Uncontrolled Levels ($/ton) 2004$
Source Categories subject to Emission Limits:								
Solid Fuel Boilers > 1000 mmbtu/hr	8	35,360	4,420	8	28,870	82%	SCR, CM + SNCR	1,000 - 2,200
Solid Fuel Boilers > 500 mmbtu/hr	5	4,700	940	5	2,950	63%	C.M. + SNCR	1,000 - 2,000
Solid Fuel Boilers > 250 mmbtu/hr	0						C.M. + SNCR	
Solid Fuel Boilers < 250 mmbtu/hr	3	277	92	3	137	49%	C.M. + SNCR	2,200 - 2,500
Gaseous and Oil Boilers	16	131	8	3	23	18%	LNB, LNB + GR	800 - 2,500
EGU Combustion Turbines	9	262	29	4	139	53%	DLNB, S.I.+ W.I., SCR	2000 - 2500
Industrial Combustion Turbines	6	74	12	2	56	76%	DLNB	1,500 - 2,500
Lime Kilns	0						C.M.	1,500 - 2,000
Glass Furnaces	2	397	199	1	301	76%	Oxy-Fire	> 2,500 (a)
Furnaces	5	135	27	5	81	60%	LNB	500 - 1,500
Asphalt Plants (3)	7	65	9	7	39	60%	LNB	800 - 2,500
Process Heating	3	107	36	3	64	60%	LNB	800 - 2,500
Reciprocating Engines (4)	12	450	38	19	360	80%	LEC, SCR	300 - 2,000
Total for Units Affected by Emission L:imits	**76**	**41,958**		**60**	**33,020**	**79%**		
Sources subject to only Combustion Tuning	60	280	5	60	41	15%	O2 & CO monitoring	net savings -$500

Notes:

1) No. of units reflect total number in the RACT source categories. Units are not affected if they are not at facilities with a PTE greater than 100 TPY.

2) Emission units may already be operating at or meeting emission limits equivalent to the proposed NOx RACT requirements.

3) The owners and operators of most asphalt plants are entering into a general permit which restricts the facility PTE to less than 25 TPY.

4) Four of the identified reciprocating engines are at asphalt plant facilities and would be exempt due to note 3.

a) Oxy-firing is a significant rebuilding which extends plant life. Cost attributable to NOx reduction < 2,000. (7)

Evaluation of Coal-fired Boilers

Large coal-fired boilers represent more than 90% of the stationary source NO_x emission in Southeastern Wisconsin. These boilers include 13 very large units used for electricity generation and 3 smaller units used to generate steam for industrial processes or space conditioning.

In the RACT evaluation for these boilers, I considered the following control technologies:

- Over-fire Air
- Low NOx Burners
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

I evaluated these control technologies singularly and in various combinations. There are also a number of factors which affected the application and effectiveness of these technologies to the coal boilers including unit size, fuel type and firing configuration. The technologies and control assumptions evaluated for each type of boiler is illustrated in Table A5.

For boilers greater than 500 mmBtu/hr, I used, control costs and control effectiveness from EPA's base data used for running the Integrated Planning Model (1). However, this size class of boilers in Wisconsin is comprised totally of electric utility boilers which in some case have already implemented the same or similar controls to those being evaluated. Therefore, where available, I incorporated information for cost submitted to the Public Service Commission in certificates of authorization and effective emission rates reported to the department. In cases where there is a significant difference, uncontrolled emission rates are included for both the general category and for the specific unit based on historic reported rates.

For boilers less than 500 mmBtu/hr, the application of technology is based primarily on EPA's recent compilation of control options for industrial boilers (6). Other sources were utilized as reference in applying the control information (4) (7).

Along with the average cost of control from an uncontrolled basis, I calculated the marginal cost of control for each option. This demonstrates the relationship of combining technologies as well as testing the incremental cost for emission units with existing controls. The incremental or marginal cost of installing additional control did not appear excessive for any option where the average cost of total control was less than the $2,500 per ton ceiling.

Table A5. Summary of the Evaluation of Control Technologies for Wisconsin Specific and Typical Source Category Coal-Fired Boilers.

						Control Technology Evaluations								
Boiler Size Class (mmBtu/hr)	Firing Configuration	Facility	Unit	Firing Capacity (mmBtu/hr)	Mega-watts	Base Emission Scenario	Base Emission Rate (lbs/ mmbtu)	Technology	Control Efficiency	Annual Cost ($M)	Controlled Emission Rate (lbs/ mmBtu)	Controlled Emission Rate w/ C.M. (1)	Cost of Measure ($/ton) (2)	Average Cost of Control ($/ton) (3)
> 1000	wall-fired	Pleasant Prairie	1	6,158	580	AU	0.46	*SCR	85%	14,695,949	0.07	0.09	1,605	1,605
> 1000	wall-fired	Pleasant Prairie	2	6,158	580	AU	0.46	*SCR	85%	12,710,697	0.07	0.09	1,364	1,364
> 1000	arch-fired	South Oak Creek	5	2,298	258	AU	0.24	*Tertiary Air	25%	525,076	0.18	0.18	1,106	1,106
						AU + tertiary air	0.18	SCR	61%	4,689,040	0.07	0.09	5,386	3,876
> 1000	arch-fired	South Oak Creek	6	2,283	260	AU	0.23	Tertiary Air	20%	531,528	0.18	0.18	1,502	1,502
						AU + tertiary air	0.18	SCR	61%	4,772,827	0.07	0.09	5,517	3,464
> 1000	tangential	Edgewater	5	4,366	380	AU	0.22	LNC3	40%	929,753	0.13	0.13	749	749
						AU + LNC3	0.13	SNCR	35%	3,248,796	0.08	0.10	5,002	2,209
						AU + LNC3	0.13	SCR	46%	7,279,567	0.07	0.09	2,765	2,833
						CU	0.46	SCR	85%	7,279,567	0.07	0.09	1,500	1,913
> 1000	tangential	South Oak Creek	7 / 8	2,608	280	AU	0.39	*LNC2	64%	912,749	0.14	0.14	327	327
						AU	0.39	SCR	82%	5,381,213	0.07	0.09	1,506	1,506
						AU + LNC2	0.14	SNCR	35%	2,420,571	0.09	0.11	4,411	999
						CU	0.46	SCR	85%	5,381,213	0.07	0.09	1,232	1,232
> 1000	cyclone	Edgewater	4	3,529	330	AU	0.79	*OFA + SB	67%	2,533,848	0.26	0.26	461	461
						AU	0.79	SCR	90%	6,102,790	0.08	0.10	827	671
						AU + OFA + SB	0.26	SCR	73%	6,102,790	0.07	0.09	3,095	1,156
500 - 1000	wall-fired (HHR)	Valley	1 - 4	846	64	AU	0.47	*LNB	23%	283,705	0.36	0.36	1,169	1,169
						AU	0.47	LNB + upgrade	40%	317,490	0.28	0.32	782	782
						AU + LNB w/ upgrade	0.28	OFA	26%	113,816	0.21	0.24	748	773
						AU + LNB w/ upgrade	0.28	SNCR	36%	576,763	0.18	0.22	2,550	1,379
						AU + LNB w/ upgrade	0.28	OFA + SNCR	52%	690,579	0.13	0.16	2,213	1,404
500 - 1000	cyclone	Edgewater	3	844	60	AU	0.79	*OFA / SB	62%	1,044,356	0.30	0.30	834	834
						AU + OFA	0.30	SNCR	40%	878,133	0.18	0.22	2,841	1,232
						AU + OFA	0.30	SCR	75%	2,061,858.81	0.08	0.09	3,558	1,696
						CU	0.86	OFA	50%	1,044,355.59	0.43	0.49	943	943
						CU + OFA	0.43	SNCR	40%	662,400.00	0.26	0.31	1,982	2,308
						CU + OFA	0.43	SCR	75%	2,061,858.81	0.11	0.13	2,482	1,603
< 250 mmBtu/h	stoker	Milwaukee County	1 - 3	140		AU + OFA	0.45	SNCR - Urea	60%	see note (4)	0.18	0.22	2,384	2,384
						CU	0.53	SNCR - Urea	60%	see note (4)	0.21	0.25	2,384	2,384

Base Emission Scenario – This is the emission basis for applying control technologies. AU = actual uncontrolled emissions of the unit based on historic data. CU = a typical uncontrolled emission rate for emission units in that source category.

Technology definitions – OFA = overfire air, LNB = low NOx burners, LNC = low NOx burners with coupled overfire air, SB = smart burn (patented optimization process), SNCR = selective non-catalytic reduction, SCR = selective catalytic reduction

* These are existing controls with demonstrated control efficiency and emission rates.

The shaded areas illustrate a technology that was not considered to be cost-effective for the RACT determination.

1) C.M. is the compliance margin account for variability of controls in meeting an emission limit. The emission rate with CM is the actual demonstrated emission rate. For added controls the assumed CM is: 15% for combustion controls, 20% for SNCR, 25% for SCR.
2)This represents the cost-effectiveness of the measure incremental to the base emission scenario controls.
3) This represents the cost-effectiveness of all measures included in the base emission scenario and the additionally applied measure versus the actual or categorical uncontrolled emission rate.
4) The cost-effectiveness of the measure is that estimated by EPA for a coal fired boiler operating at 50% capacity converted to 2004$ (6)

References

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11) WDNR, 2006. *BACT analysis of new lime kiln at Superior Lime.* Bureau of Air Management.

12) WDNR, 2006. *2002 Air Emissions Inventory and compliance submittals.* Bureau of Air Management.

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List of Acronyms

- CM, Comb. Mod. – combustion modification
- DLNB – dry low NOx burner
- OFA – overfire air
- GR – gas recirculation
- LEA – low excess air
- LEC – low emission combustion
- LNC2, 3 – low NOx concentric firing
- LNB – low NOx burner
- Oxy-firing – processed oxygen used for combustion in place of air
- SI – steam injection
- SCR – selective catalytic reduction
- SNCR – selective non-catalytic reduction
- WI – water injection
- HHR – High Heat Release
- LHR – Low Heat Release

Attachment B. Analysis of Electric Utility NOx Emissions under the proposed CAIR and RACT rules.

Facility	Unit ID	Heat Input -- Ave of top 3, 2000-2004	NOx Emissions by Program and Compliance Year				
			2009		2012		2015
			(a) CAIR I Allocations (2009 - 2014)	EGU RACT Limits	EGU RACT Limits	RACT Emissions Averaging (Less 10%)	(b) CAIR II Estimated Allocations
Pleasant Prairie	1	48,186,350	3,528	3,614	2,409	2,168	3,012
Pleasant Prairie	2	49,036,435	3,578	3,678	2,452	2,207	3,065
South Oak Creek	5	15,827,661	1,173	1,424	1,424	1,282	989
South Oak Creek	6	15,728,881	1,200	1,416	1,416	1,274	983
South Oak Creek	7	22,396,506	1,618	1,680	1,120	1,008	1,400
South Oak Creek	8	21,363,295	1,630	1,602	1,068	961	1,335
Valley	1	4,412,992	224	441	331	298	276
Valley	2	4,279,358	224	428	321	289	267
Valley	3	4,718,643	224	472	354	319	295
Valley	4	4,664,807	224	466	350	315	292
Edgewater	3	5,151,457	338	515	386	348	322
Edgewater	4	20,756,100	1,576	1,557	1,038	934	1,297
Edgewater	5	28,547,851	2,136	2,141	1,427	1,285	1,784

Total Emissions (tons) ===>	**17,673**	**19,434**	**14,096**	**12,687**	**15,317**
Reduction Below CAIR I (tons) ===>		(1,761)	3,577	4,986	
Reduction Below CAIR II (tons) ==>		(4,117)	1,220	2,630	

Total Emissions less 15% compliance margin for meeting RACT emission limit (c) (tons) ===>	**17,673**	**16,519**	**11,982**	**10,784**	**22,585**

a) The first phase CAIR allocations are those contained in the proposed rule Board Order AM-03-06.

b) The CAIR allocations are determined on an ongoing basis after 2014. The allocations are estimated here by EPA's analysis indicated a program-wide emission rate of ~ 0.125 lbs/mmbtu.

c) A compliance margin is applied to meeting only an emission limit in estimating actual emissions. Under the CAIR program allocations may be purchased to address a shortfall in emission allocations.

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