Technical Support Document

State of Colorado

CATEGORICAL REASONABLY AVAILABLE CONTROL TECHNOLOGY REVIEW for Boilers, Turbines, Engines, Glass Melt Furnaces and Aggregate Kilns at Major NOx Sources in the Denver Metro/North Front Range Ozone Nonattainment Area

Supporting the

Denver Metro/North Front Range
State Implementation Plan for
the 2008 8-Hour Ozone
National Ambient Air Quality Standard

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1) INTRODUCTION

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as a Marginal nonattainment area for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that Colorado's Marginal ozone nonattainment area failed to attain the 2008 8-hour Ozone NAAQS and therefore reclassified the DMNFR area to Moderate, effective June 3, 2016, and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264, March 6, 2015). Pursuant to CAA § 182(b)(2), Reasonably Available Control Technology ("RACT") is applicable to each category of VOC sources covered by a Control Techniques Guideline ("CTG") for which Colorado has sources in the nonattainment area ("NAA"), and all other existing major stationary sources of VOC or NOx located in the NAA. RACT is defined 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[1]."*** The application of a potential control technology could involve a distinct piece of control equipment, it could involve a work practice, an emission standard, some combination of these, existing controls or nothing at all.

For many major sources or source emission points in the DMNFR area, RACT requirements are already established in federally enforceable permits or the source must comply with a federal New Source Performance Standard ("NSPS") or a National Emission Standard for Hazardous Air Pollutants ("NESHAP"), although these requirements are not necessarily in the SIP. Consequently, in 2016, the Air Quality Control Commission ("AQCC"), established in Regulation Number 7, new RACT requirements for many VOC sources covered by a CTG and many major sources of VOC and/or NOx in the DMNFR area for inclusion in the SIP. The 2016 revisions to Regulation Number 7 control NOx by establishing a work practice for combustion equipment in Section XVI and source specific RACT limits or standards in Section XIX. Since then Colorado has continued to apply RACT to all VOC sources covered by a CTG and all existing major sources of VOC and NOx.

In order to satisfy the Moderate RACT SIP requirement to establish categorical RACT for all existing major sources of VOC and/or NOx in the DMNFR, the Commission initially incorporated by reference several NSPS or NESHAP on November 17, 2016. These RACT requirements became effective on January 1, 2017.[2] However, during that rulemaking, the Commission determined that little, if any, additional controls could be implemented by certain major sources by the SIP submittal deadline of January 1, 2017. The Commission also determined that not all major sources or major source emission points were subject to

[1] See 44 FR 53762, Sept. 17, 1979.

[2] The Commission previously adopted source specific RACT requirements by incorporating by reference certain NSPS and NESHAP for several source categories. These requirements were previously contained in Regulation 7, Section XIX.D.-G. While the substantive requirements of these provisions will not change during this rulemaking, the Section numbers will be changed to Sections XIX.A-D. Additionally, the turbine requirements that were previously contained in Regulation 7, Section XIX.C. have been moved to Section XVI.4.b.

existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Colorado's Regional Haze SIP.

For those sources that were not subject to other, existing regulatory RACT requirements, the Commission required owners or operators to submit a RACT analysis for the facility or specific emission points to the Division by December 31, 2017, to inform development of categorical RACT rules. In these RACT analyses, sources were required to identify potential options to reduce VOC and/or NOx emissions, depending on which pollutant(s) the source was major for, propose RACT, propose associated monitoring, propose a schedule for implementation, and include economic and technical information demonstrating why the proposal established RACT for the particular facility or emission point(s). Table 1 identifies the DMNFR NAA major sources required to submit RACT analyses by former Section XIX.B[3].

Table 1: Major Stationary Sources Submitting Analyses under Reg. 7, Section XIX.B

Source	Source ID	Major	Unit Type	Emissions Point
Anheuser-Busch	069-0060	VOC/NOx	Boilers/Brewing	All points ≥ 2 tpy VOC and 5 tpy NOx (4-boilers 001, 002)
Buckley USAF	005-0028	NOx	Engines/test cell	102, 103*, 104*, 105*, 101
Carestream Health	123-6250	NOx	Boilers	004*
Colorado State University	069-0011	NOx	Boilers	003, 005, 007, 013*
IBM	013-0006	NOx	Engines & Boilers	088*, 090*, 001*, 011, 095
MillerCoors Golden Brewery	059-0006	VOC/NOx	Brewing	All points ≥ 2 tpy VOC and 5 tpy NOx
MMI/EtOH	059-0828	VOC/NOx	Brewing waste	All points ≥ 2 tpy VOC and 5 tpy NOx
Nutri-Turf	123-0497	VOC/NOx	Brewing waste	All points ≥ 2 tpy VOC and 5 tpy NOx
Owens-Brockway Glass	123-4406	NOx	Glass melt furnaces	All points ≥ 5 tpy NOx (001-023, 025)
Public Service Company - Cherokee	001-0001	NOx	Turbines	028, 029
Public Service Company - Fort Saint Vrain	123-0023	NOx	Turbines & Boilers	010, 011, 001
Rocky Mountain Bottle	059-0008	NOx	Glass melt furnaces	001*
Suncor	001-0003	VOC/NOx	Boilers	309*, 019, 021, 023
Tri-State G & T - Frank Knutson	001-1349	NOx	Turbines	001, 003
Trinity (TXI)	059-0409	NOx	Shale Kiln	001
University of Colorado - Power House & East District/Williams Village	013-0553	NOx	Boilers	001, 002, 012, 013
	013-0019	NOx	Boilers	001, 002

** Multiple pieces of equipment are listed under one emission point*

[3] The Division now proposes to delete Section XIX.B and move the list of sources to the Statement of Basis and Purpose.

In addition to the above listed major sources, the Division sent Section 111 letters[4] to certain major sources located in the DMNFR NAA requesting that RACT analyses be submitted no later than December 31, 2017 for specifically identified emission points where RACT had been established as combustion process adjustment with no requirement for specific emission controls. Table 2 identifies the DMNFR NAA major sources covered by the current proposal that submitted RACT analyses in response to a Section 111 request.

Table 2: Covered Sources that Submitted RACT Analyses Pursuant to Section 111 Requests

Source	Source ID	Major	Unit Type	Emissions Point
CENC	059-0820	VOC/NOx	Boilers	001, 002
Public Service Company - Denver Steam	031-0041	NOx	Boilers	001, 002
Public Service Company - Fort Lupton	123-0014	NOx	Turbines	001, 002
Public Service Company - Valmont	031-0001	NOx	Turbines	002
Public Service Company - Zuni	031-0007	NOx	Boilers	001, 002, 003
Kerr-McGee Gathering - Platte Valley Gas Plant	123-0057	VOC/NOx	Turbine & Engines	052, 038-041, 044, 047-049
WGR Wattenberg Gas Processing Plant	001-0025	VOC/NOx	Boiler, & Turbine	012, 021

** Multiple pieces of equipment are listed under one emission point*

The Division also received RACT analysis information from another source listed in Table 3, Metro Wastewater-GDF Suez. This facility took steps to lower the facility-wide emissions below major source thresholds, but was ultimately unable to do so.

Table 3: Metro Wastewater-GDF Suez RACT analysis

Source	Source ID	Major	Unit Type	Emissions Point
Metro Wastewater-GDF Suez	001-0097	NOx	Turbines, Boilers, Flares	001*, 010*, 017*

** Multiple pieces of equipment are listed under one emission point*

The Division conducted an extensive review of the RACT analyses to inform the development of categorical rules. The unique mix of emission sources resulted in the Division developing proposed categorical RACT requirements, collectively referred to as "stationary combustion equipment" in Section XVI.D of Reg. 7 for existing major sources[5] of NOx in the DMNFR NAA. These proposed revisions will further establish categorical RACT requirements for major sources of NOx in the DMNFR NAA. This TSD focuses solely on establishing RACT for five categories of existing major sources of NOx (stationary combustion equipment) for which the Division determined Colorado's SIP did not contain adequate provisions: boilers, stationary combustion turbines, lightweight aggregate kilns, glass melting furnaces and compression ignition reciprocating internal combustion engines ("RICE").

[4] Pursuant to authority under Colorado Revised Statue Section 25-7-111(2)(i)

[5] A separate rulemaking and TSD will be developed to address RACT for major sources of VOC in the DMNFR NAA.

2) MAJOR SOURCE RACT

Pursuant to CAA Section 182(b), Colorado must include RACT requirements in its SIP for major sources of VOC and/or NOx that existed on the effective date of the reclassification of the DMNFR as a moderate ozone nonattainment area. The CAA does not define RACT. However, EPA has defined 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 Fed. Reg. 53762 (Sept. 17, 1979). RACT requirements can be expressed in the form of emissions limitations, work practice standards, or other operation and maintenance requirements. RACT provisions established in the SIP prior to the reclassification may remain unchanged if they still constitute RACT.

The CAA uses a cooperative-federalism approach to regulate air quality. U.S. Magnesium, LLC v. EPA, 690 F.3d 1157, 1159 (10th Cir.2012). States have the primary responsibility for preventing air pollution within their boundaries. CAA § 101(a)(3) and 107(a); Train v. Natural Resources Defense Council, Inc., 421 U.S. 60 (1975), 79, 86-87. EPA sets nationwide requirements, including National Ambient Air Quality Standards, and designates nonattainment areas. CAA §§ 107(d)(1)(B), 109. States determine how to attain the NAAQS within their boundaries and submit plans meeting the requirements of the Act. CAA § 172(b). States determine what emission limitations constitute RACT, revise their SIPs, and submit the SIP revisions to EPA for approval under CAA § 110(k). Cooperative federalism achieves uniform air quality standards while giving states flexibility over how to implement those standards.

RACT determinations may vary from state to state. RACT is grounded in the concepts of reasonableness, technological feasibility, and economic feasibility. The definition of RACT preserves state primacy and allows for differences between the states, so long as RACT determinations are reasonable and consistent with CAA requirements. States have discretion when establishing RACT requirements. Emission limitations and other RACT provisions that are reasonable for a particular mix of sources, operating scenarios, existing controls and ambient ozone conditions in one jurisdiction might not be reasonable in other jurisdictions. Colorado exercised its discretion as the primary regulator of air quality to determine the emission limitations that are reasonably available within the state's borders. Some jurisdictions may have individual RACT requirements for particular sources that might be more or less stringent than Colorado's proposal in some specific circumstances. Ultimately, the Division developed the stationary combustion equipment categorical RACT standards based on a detailed review of the information provided by owners and operators of major NOx sources in the DMNFR, an examination of the EPA RACT/BACT/LAER Clearinghouse for similar emission points, and consideration of CAA§ 182(b) RACT requirements for other ozone non-attainment areas. In evaluating all of this information as is relates to Colorado's unique source mix, the RACT proposed herein, is reasonable, economically feasible, achieves emission reductions and constitutes RACT for combustion equipment as a source category in the DMNFR.

Colorado has major sources of VOC and/or NOx in the ozone nonattainment area. While many of these sources are subject to regulatory RACT requirements included in Colorado's SIP, other sources or source emissions points are subject to individual RACT requirements established in federally enforceable permits as a minor source RACT requirement or inclusion of an applicable federal NSPS or NESHAP. Since the adoption of Colorado's minor source RACT permitting requirements in 1981, many newly constructed or modified emissions units have been controlled to RACT levels through the permitting process in the DMNFR.

However, as a Moderate nonattainment area, Colorado must include in the SIP provisions to implement RACT for Colorado's existing major sources in the DMNFR, and the Division proposes to do so on a categorical basis. Establishing RACT on a categorical basis is a distinctly different process from Colorado's minor source RACT permitting requirement found in Regulation 3, Part B, Section III.D.2. Minor source RACT permitting is specific to new or modified sources (i.e. sources that have already committed to a capital expenditure to construct or modify a process) which can more easily accommodate changes prior to construction.

Categorical RACT applies more broadly to source categories, including existing sources and equipment. This inclusion of existing equipment significantly impacts costs, as these sources are not already committed to a capital expenditure and would not otherwise shut down to add retrofit controls. This ultimately impacts the decision on what controls are determined to be reasonably available, and technologically and economically feasible for the source category as a whole. In addition, the RACT emission limits in some Colorado permits are based on emission controls that were already in place or planned by a particular source. These permits may contain RACT limits that are more stringent than would otherwise be established for the source category as a whole. Thus, categorical RACT may in some cases be different from any RACT established for a specific source or piece of equipment under the minor source permitting RACT requirement. Generally, RACT is analyzed in terms of the cost per ton of pollutant reduced ($/ton). Accordingly, sources with low emissions often show that additional emission controls are reasonably available and technically feasible but are not cost effective.

In order to satisfy the Moderate RACT SIP requirement to establish RACT for all existing major sources of VOC and/or NOx in the DMNFR, the Commission initially incorporated by reference several NSPS or NESHAP regulations on November 17, 2016. The details are explained in a document entitled: *Technical Support Document for Reasonably Available Control Technology for Major Sources dated October 17, 2016*.

In May 2017, the Division distributed a "RACT Analyses" document entitled "*Overview of RACT Analyses for Major Sources in the DMNFR 2008 Ozone Nonattainment Area*" that provided Colorado's perspective on an acceptable method for owners or operators of major sources to prepare RACT analyses in support of the potential development of categorical rules that satisfy RACT requirements for moderate ozone non-attainment areas under the Clean Air Act. The document suggested the process, content and format for preparing a RACT analysis submittal and requested that sources include the following in their RACT analyses: background information on the source and associated emission points, a summary of functions and activities, identification of applicable permits and emission points, technical details of emission points, such as equipment type and design, fuel type, power rating, existing control technology, emission factor basis and whether any monitoring technology was installed. It was suggested that the RACT analyses also include a top-down review of applicable emission control technologies, the effectiveness of the potential control technology and a discussion of the elimination of any technologically infeasible control options. For those technically feasible control options for a specific emission point, it was recommended that the owner or operator provide a detailed cost analysis that identified the capital cost of emission control equipment, such as engineering, delivery, labor, construction, installation, start-up and commission costs, and annual operating costs, such as energy, maintenance, taxes, insurance, contingency, monitoring, recordkeeping and reporting costs. It was also suggested that these costs be generally standardized across all source emission points on an annual basis using an interest rate assumption of 5% and a useful equipment life generally accepted for the

emission control equipment being evaluated, which was typically 15 years.

All the major sources submitted a RACT analysis on time and the Division conducted a technical review those RACT analysis to inform the RACT proposal. Ultimately, the Division developed the stationary combustion equipment categorical RACT standards based on a detailed review of the information provided by owners and operators of major NOx sources in the DMNFR, an examination of the EPA RACT/BACT/LAER Clearinghouse for similar emission points, and consideration of CAA§ 182(b) RACT requirements for other ozone non-attainment areas. This TSD includes a detailed analysis of the following five stationary combustion equipment source categories: (a) Boilers; (b) Stationary Combustion Turbines; (c) Compression Ignition Reciprocating Internal Combustion Engines; (d) Lightweight Aggregate Kilns; and (e) Glass Melting Furnaces.

3) BOILERS

a) Emissions Units Analyzed

The Division reviewed the technical RACT analysis information submitted by the operators of boilers located at major stationary sources of NOx located in the DMNFR ozone nonattainment area. Table 4 below provides basic information for each boiler potentially subject to the RACT review process and lists the boiler rating in million British thermal units per hour ("MMBtu/hr").

Table 4: DMNFR Major Stationary Sources - Boiler Information

	Facility Name	Source ID	Year Installed	Boiler Rating (MMBtu/hr)	Avg. NOx Emissions[6] (tons/yr)	NSPS
1	Anheuser Busch	069-0060-001	1988	99.0	47.5	N/A
			1988	99.0	47.5	N/A
			1988	99.0	47.5	N/A
			1988	99.0	47.5	N/A
2	Carestream	123-6350-004	1974	206.0	30.6	N/A
			1974	206.0	30.6	N/A
3	Colorado Energy Nations Company	059-0820-001	1954	288.0	50.0	N/A
		059-0820-002	1954	288.0	74.2	N/A
4	Colorado State University	069-0011-003	1984	181.0	29.2	N/A
		069-0011-005	1960	88.0	0.9	N/A
		069-0011-007	1966	181.0	62.2	N/A
		069-0011-013	2007	12.6	1.7	N/A
			2007	12.6	1.7	N/A
5	CU-Power House - West District	013-0553-001	1958	125.5	36.3	N/A
	CU-Power House -	013-0553-002	1966	151.0	32.7	N/A

[6] Generally, the average NOx emissions are based on Air Pollution Emissions Notice (APEN) reported emissions over the period (2014-2016). However, sources may choose to report either allowable or actual emissions. The three year period could include one APEN report or multiple APEN reports depending source specific reporting schedule.

	Facility Name	Source ID	Year Installed	Boiler Rating (MMBtu/hr)	Avg. NOx Emissions[6] (tons/yr)	NSPS
	West District					
	CU-Power House - East District	013-0553-012	2013	62.5	9.1	Dc
	CU-Power House - East District	013-0553-013	2013	125.0	19.8	Db
	CU-Williams Village	013-0553-016	1965	37.5	1.4	N/A
	CU-Williams Village	013-0553-017	1965	39.5	1.5	N/A
6	IBM	013-0006-001	1965	60.0	18.5	N/A
			1968	66.0	18.5	N/A
		013-0006-011	2002	54.4	4.0	N/A
		013-0006-095	2014	32.7	2.8	N/A
7	Metro Wastewater - GDF Suez[7]	001-0097-010	1977	12.5	0.1	N/A
			1977	12.5	0.1	N/A
			1977	12.5	0.1	N/A
8	Public Service-Denver Steam	031-0041-001	1972	210.0	48.4	N/A
		031-0041-002	1974	243.0	123.7	N/A
9	Public Service-Fort St. Vrain	123-0023-001	1969	70.2	10.2	N/A
10	Public Service-Zuni	031-0007-001	1948	505.0	46	N/A
		031-0007-002	1948	211.0	0	N/A
		031-0007-003	1954	970.0	0	N/A
11	Suncor	001-0003-019	1963	130.0	96.8	J
		001-0003-021	1990	111.0	8.6	J
		001-0003-023	1990	161.0	12.1	J
		001-0003-309	1990	189.0	11.0	Db
			1990	189.0	11.0	Db
12	WGR Wattenberg	001-0025-012	1985	16.8	0.1	N/A

The boilers analyzed vary widely in terms of operation, size, age, emissions, and existing NOx controls. Natural gas is the primary fuel for each boiler analyzed and the Division recommended an analysis for backup fuels only if a boiler's emissions are greater than 1 ton per year due to firing backup fuels. Fuel oil is a common backup fuel; however, combustion of fuel oil in the boilers analyzed is rare and occurs during periods of very limited testing or during infrequent periods of natural gas curtailment - typically in the winter. Consequently, RACT was not analyzed for fuel oil and is not discussed further in this section.

b) Potential NOx Controls Evaluated

The Divisions' RACT Analysis Overview document identified a top-down list (see Table 5 below) of potential boiler retrofit NOx control options or combinations of options that

[7] Metro Wastewater-GDF Suez submitted a RACT analysis after it was determined that the Title V NOx permit limit could not be lowered below the major stationary source threshold of 100 tpy.

operators could consider in the RACT analysis. Sources were also advised to evaluate not only the installation of add on controls but evaluate potential work practices in the RACT analysis.

Table 5: Top-Down List of Potential Boiler Emission Controls

NOx Emission Control Options for Boilers
Selective Catalytic Reduction ("SCR")
Selective Non-Catalytic Reduction ("SNCR")
Ultra-Low NOx Burners ("ULNB")
New Generation of Low NOx Burners ("LNB")
Over-fire Air ("OFA"), Separated OFA ("SOFA"), Close-coupled OFA ("CCOFA")
Flue Gas Recirculation ("FGR")
SCR + ULNB + OFA/SOFA/CCOFA
SCR + LNB + OFA/SOFA/CCOFA
SNCR + ULNB
SNCR + LNB
ULNB + OFA/SOFA/CCOFA
LNB + OFA/SOFA/CCOFA
ULNB + FGR
LNB + FGR

The operators provided an evaluation of potential emission controls identified as technically feasible. Feasible controls were evaluated to determine the associated emission reduction effectiveness and an estimate of the annualized cost for each retrofit emission control. The cost per ton of pollutant reduced was calculated using the annual emission totals based on two levels of emissions: actual emissions and allowable emissions.

c) NOx Control Cost Ranges for Boilers

The Division reviewed the RACT analysis submittals from the operators of the boilers[8] to determine the potential emission control costs associated with various feasible NOx emission control options. The control costs were calculated based on the cost information provided by the operators and using a standardized estimate of actual emissions based on the most recent three-year average (2014-2016) of Air Pollution Emissions Notice (APEN) reported NOx emissions. The estimated cost ranges for each emission control option and the average control cost is summarized in Table 6. All costs are listed in 2017 dollars.

Table 6: Control Efficiencies and Cost Ranges for Various Boiler Emission Control Retrofit Options based on APEN Reported Emissions

Control Technology	Estimated % NOx Reduction from Uncontrolled Emissions*	Average of Control Costs using APEN Reported Emissions ($/ton)
SCR	60-90%	$76,221
SNCR	25-50%	$61,483
ULNB	50-91%	$11,853

[8] Metro Wastewater-GDF Suez is a major NOx source, so the 3 boilers were included in Table 1, but these boilers emissions are well below the NOx RACT emission point screening threshold of 5 tpy, so no cost analysis was provided.

Control Technology	Estimated % NOx Reduction from Uncontrolled Emissions*	Average of Control Costs using APEN Reported Emissions ($/ton)
LNB + FGR	60-90%	$55,081
LNB	30-60%	$44,700
FGR	30-50%	$76,979

**Actual control technology percent emission reduction is probably lower because many boilers already have some level of pre-combustion control.*

The Division used APEN reported emissions as a proxy for actual emissions. Actual emissions are likely to be lower than reported emissions because some sources choose to report allowable emissions on the APEN. This means the $/ton control costs shown in Table 6 are conservatively low, and would rise if true actual emissions were known. The estimated emission reduction for various pre and post combustion controls does vary depending on fuel, method of operation, boiler size, burner configuration and baseline emissions. The above listed average emission control costs suggest that both pre and post combustion controls are very expensive for most boilers based on reported emissions. In the 2016 RACT rulemaking, the Division evaluated the cost of emission controls based on APEN reported emissions because EPA specified a RACT implementation date of January 1, 2017. In situations where actual emissions are significantly below potential emissions, actual emissions provide a more realistic evaluation of the true cost of implementing emission controls at the most current emission rates.

However, if actual emissions may rise in the future, it may be more appropriate to consider allowable emissions. In these situations, limiting the cost effectiveness evaluation to only actual emissions may distort the cost effectiveness of a particular emission control. If a source substantially increases emissions in the future, controls originally deemed too expensive might become cost effective. Consequently, because EPA staff asked Colorado to expand the implementation of RACT controls beyond the original January 1, 2017 date, the Division further evaluated each technologically feasible emission control based on allowable (permitted) emissions for each boiler unit to determine the cost effectiveness.

Table 7: Control Efficiencies and Cost Ranges for Various Boiler Emission Control Retrofit Options at Allowable Emissions

Control Technology	Estimated % NOx Reduction from Uncontrolled Emissions*	Average of Control Costs ($/ton)
SCR	60-90%	$15,223
SNCR	25-50%	$8,849
ULNB	50-91%	$4,184
LNB + FGR	60-90%	$6,810
LNB	30-60%	$6,629
FGR	30-50%	$10,133

**Actual control technology percent reduction is probably lower because many boilers already have some level of pre-combustion control.*

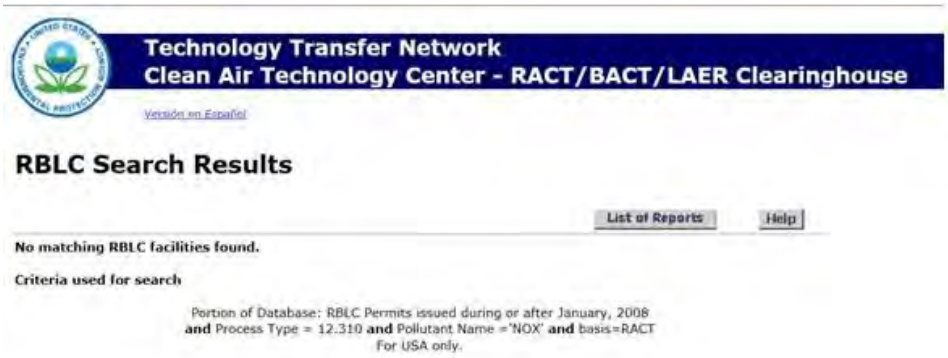
Based on the control costs listed above in Table 7, the Division concludes that SCR, SNCR and FGR are too costly for consideration as SIP RACT for the boiler category. However, it appears that most low NOx burner retrofit/upgrades are cost effective and technically feasible for all boilers subject to the proposed categorical standard. Consequently, the Division concludes that low NOx burner retrofits for natural gas-fired boilers over 100 MMBtu/hr are both

technically feasible and cost effective.

A few boilers that would be subject to the proposed categorical RACT standard currently use an AP-42 emission factor to report NOx emissions. Thus, it is unclear whether compliance with the proposed RACT standard is possible without the addition of retrofit controls for these boilers, although a few compliance options are available including (1) remain below the 20% capacity factor to maintain the exemption from the categorical standard, or (2) conduct stack testing to determine the actual emission rates. If the stack test demonstrates emissions below the standard, then continue to demonstrate compliance by installing a continuous emissions monitoring device. Alternatively, if the stack test shows emissions above the standard, the source has 3-years to install the burner upgrades necessary to demonstrate compliance along with installing a continuous emissions monitoring device.

d) EPA RACT/BACT/LAER Clearinghouse for Boilers

The Division performed a nationwide search of the EPA RACT/BACT/LAER Clearinghouse (**"RBLC"**) database to see if any recent NOx RACT determinations on natural gas-fired boilers[9] could inform an appropriate RACT threshold for boilers. The below screen capture indicates that no RACT determinations are listed for boilers/furnaces (>100 MMBtu/hr) firing natural gas. The RBLC standard search used final determinations based on process type code 12.310 - Industrial Size Boilers/Furnaces (>100 MMBtu/hr) firing natural gas (includes propane and liquefied petroleum gas).



The Division concludes that the RBLC provides minimal insight on appropriate RACT thresholds for natural gas fired boilers.

*e) R*eview of Other States NOx RACT for Natural Gas-fired Boilers

As noted in the third column of Table 8 below, a number of the listed states are part of an ozone transport region ("OTR"). Other states have areas that are currently or previously designated as an ozone non-attainment area for the 1-hour 1979 Ozone NAAQS (revoked), the 8-hour 1997 Ozone NAAQS (revoked), or the 8-hour 1997 Ozone NAAQS. Some ozone areas are non-attainment for multiple ozone standards.

California has a number of ozone non-attainment areas with classifications ranging from

[9] The RBLC standard search used final determinations based on process type code 12.310 – Natural Gas (includes propane and liquefied petroleum gas).

"Marginal" to "Extreme", which limits the utility of evaluating and comparing RACT thresholds because all areas likely contribute to the two areas with the highest ozone levels (Los Angeles Basin and San Joaquin Basin), thereby indirectly influencing the economic feasibility of RACT for all surrounding areas regardless of classification. Extreme areas, to some extent may influence the level of what is determined as RACT for California areas with a moderate classification, which is likely to differ from what other moderate areas outside of California would determine as RACT. Accordingly, California was excluded from the table because it is difficult to ascertain the impact on the economic feasibility and associated RACT stringency for moderate areas in close proximity to extreme areas.

Table 8: Other States NOx Limits for Natural Gas-fired Boilers

State	Geographic Applicability	Ozone Region	50-100 MMBtu/hr Boilers	100-250 MMBtu/hr Boilers
			NOx Limit in lbs/MMBtu	NOx Limit in lbs/MMBtu
CT	Statewide	OTR	0.2 to 0.43	0.2 to 0.43
DE	Statewide	OTR	LEA, LNB, FGR*	0.2
FL	Broward, Dade & Palm Beach Counties	NAA	0.2 to 0.5**	0.2 to 0.5**
IL	Chicago & St Louis Areas	NAA	Tune-up	0.08
IN	Clark & Floyd Counties	NAA	No limits	0.2
LA	Baton Rouge 5 Counties & Region of Influence	NAA	0.1 to 0.2	0.1
MA	Statewide	OTR	0.1	0.2
MD	Select counties	NAA	Tune-up	0.2
MO	St. Louis area	NAA	No limits	0.2 to 0.5
NC	Charlotte – 6 county area	NAA	0.3	0.3
NJ	Statewide	OTR	0.1 to 0.5	0.1
NY	Statewide	OTR	0.05	0.06
OH	Cleveland -8 county area	NAA	0.1	0.1
PA	Statewide	OTR	0.08	0.08
TN	5 counties	NAA	Source specific RACT	Source specific RACT
TX	Beaumont area	NAA	0.1	0.1
VA	Northern VA	NAA	0.2	0.2
WI	Milwaukee 7 county area	NAA	No limits	0.08

** LEA=low excess air; LNB = low NOx burners; FGR = flue gas recirculation*
*** Depends on fuel and firing configuration*

f) RACT Determination for Boilers

In the DMNFR, any major NOx source that has combustion equipment with uncontrolled actual NOx emissions greater than or equal to five tons per year is subject to combustion process

adjustment ("CPA") requirements. The CPA requirements, adopted in 2016 establish RACT for the sources subject to Regulation Number 7, Section XVI.D.2 and satisfy the requirements of CAA § 182(b)(2) unless the source is subject to additional RACT requirements under other provisions of Colorado's SIP. The combustion process adjustment provision specifies that boilers must be inspected at least annually[10] to ensure that the burner and combustion controls are properly operated and maintained. Combustion process adjustment requires inspection of the burner and combustion controls to ensure they are functioning correctly. If not, the components are either cleaned, or if necessary, replaced. The flame pattern is also evaluated and adjusted as necessary to optimize the combustion process. The system controlling the air-to-fuel ratio is inspected to ensure that it is correctly calibrated and functioning properly. Measurements from a continuous emissions monitoring system ("CEMS") or a portable analyzer are used to monitor the CO and NOx concentrations in the exhaust stream to ensure that any of the foregoing adjustment or maintenance activities result in optimized combustion. The owner or operator is required to keep records of combustion process adjustment activities and must create a report each year.

In addition to the combustion process adjustment requirements for boilers and based on a review of operator provided information, consideration of Colorado's unique mix of boilers in the DMNFR NAA, other states RACT regulations, EPA NSPS regulations and EPA guidance including the RACT/BACT/LAER Clearinghouse, the Division proposes to establish a boiler categorical RACT standard of 0.2 lbs/MMBtu (for gaseous and liquid fuel-fired) based on a 30-day rolling average that applies to boilers with a design heat input ≥ 100 MMBtu/hr.

The proposed boiler categorical RACT standard is consistent with the federal NSPS Subpart Db, which establishes NOx standards of performance for steam generating units > 100 MMBtu/hr constructed, modified, or reconstructed after June 19, 1984. The EPA last reviewed the boiler standards back in 2011[11].

g) Continuous Emissions Monitoring System for Boilers

Twelve boilers operate a continuous emissions monitoring system. The remaining 23 boilers track and report NOx emissions based on a periodic stack test, a manufacturer emission factor or an AP-42 emission factor. A number of boilers may qualify for the 20% capacity factor exemption, however the average of operations during the first 3-year period (2018-2020) will determine whether combustion equipment qualify. There are six boilers subject to the categorical RACT standard that currently either rely on a periodic stack test (2 boilers) or an AP-42 emission factor (4 boilers) to report NOx emissions. Since categorical RACT requires demonstrating compliance with a NOx standard, the use of an AP-42 emission factor is not appropriate to demonstrate compliance without performance testing. Sources will have three years to determine if controls are required to meet the proposed standard and install CEMS for monitoring continued compliance with the standard.

The cost for the installation, operation, and maintenance of a CEMS device will somewhat depend on whether the boiler is currently equipped with any existing CEMS infrastructure, such as access to the stack and nearby electrical power. The Division estimates that capital costs (excluding staffing) for those sources may range from approximately $150,000 –

[10] The frequency of inspections could be more frequent depending on whether the emissions unit is subject to a NSPS or NESHAP.

[11] See EPA docket EPA-HQ-OAR-2011-0044

$200,000, depending on the complexity of the monitoring system. The annual cost of operating a CEMS (including staffing, recordkeeping and reporting) is conservatively estimated to be $26,000 without capital recovery and $49,000 with capital recovery[12]. It is possible that for facilities with substantial safety requirements, such as at a refinery, the costs of installing and maintaining CEMS could be considerably more. The foregoing cost estimates are based on EPA's Continuous Emission Monitoring System Cost Model. Most operators did provide some CEMS cost information in the RACT analysis that was consistent with the CEMS Cost model estimates. Capital cost estimates include planning, equipment, support facilities, hardware, installation, certification, and the development of a QA/QC plan. Annual cost estimates include day-to-day activities, annual relative accuracy test audits, cylinder gas audits, recordkeeping and reporting, and annual quality assurance and operations and maintenance review and updates.

4) STATIONARY COMBUSTION TURBINES

As a part of the November 17, 2016 revisions to Regulation 7, the Commission established RACT for stationary combustion turbines at major sources of NOx and/or VOC located within the DMNFR NAA. At the time, RACT for these select combustion turbines was established in Section XIX.C. as combustion process adjustment and compliance with 40 CFR Part 60, Subpart GG or Subpart KKKK, which are federal rules that establish individual source-specific NOx emission limits and monitoring procedures based on the maximum design capacity, operational configuration, and year of construction for each stationary combustion turbine.

As discussed in the Introduction, the Commission determined that not all major sources or major source emission points were subject to existing regulatory RACT requirements in Regulation Number 7. Accordingly, the Commission required owners or operators to submit a RACT analysis for the facility or specific emission points to the Division by December 31, 2017, to inform development of categorical RACT rules. Additionally, through Section 111 letters, the Division directed several other major sources to submit RACT analyses by December 31, 2017 as shown in Table 2. Metro Wastewater-GDF Suez, listed in Table 3, also submitted a RACT analysis after it was determined that the Title V NOx permit limit could not be lowered. This section provides the technical basis for the proposed categorical RACT determination for stationary combustion turbines. Note that "turbine" and "stationary combustion turbine" are used interchangeably throughout this section.

a) Emissions Units Analyzed

A stationary combustion turbine is defined in the proposed rule as "*a non-mobile, enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine. Stationary combustion turbines can be simple cycle or combined cycle and they may or may not include a duct burner.*" The Division reviewed RACT analyses and Division records for stationary combustion turbines located at major sources of NOx located within DMNFR NAA. Table 9 provides the basic information for each turbine potentially subject to the RACT review process and lists the turbine rating in

[12] Capital Recovery in this context means the Operator of the boiler recoups the initial investment in the CEMS device.

million British thermal units per hour ("MMBtu/hr").

Table 9: DMNFR Major Stationary Sources – Stationary Combustion Turbines

Facility Name	Source ID	Turbine Rating (MMBtu/hr)	Avg. NOx Emissions[13] (tons/yr)	Configuration
PSCo- Fort Saint Vrain	123-0023-010	1,467.0	12.3	Simple
	123-0023-011	1,467.0	11.5	Simple
PSCo- Fort Lupton	123-0014-001	662.6	3.4	Simple
	123-0014-002	662.6	3.4	Simple
PSCo- Valmont	013-0001-002	661.0	3.2	Simple
Tri-State- Frank Knutson	001-1349-003	840.3	1.2	Simple
	001-1349-001	840.3	1.3	Simple
Kerr-McGee- Platte Valley	123-0057-052	37.9	44.8	Simple
Wattenberg	001-0025-021/22	24.5	16.1	Combined
PSCo- Cherokee	001-0001-029	597.0	76.1	Combined
	001-0001-028	597.0	72.5	Combined
Metro Wastewater- GDF Suez	001-0097-001-01	42.8	30.3	Simple
	001-0097-001-02	42.8	30.3	Simple

Although emissions of some stationary combustion turbines were below the screening threshold of 5 tons per year due to infrequent operation, RACT analyses were submitted to further help inform the categorical rulemaking. The stationary combustion turbines that were analyzed vary widely in terms of operation, size, age, emissions, and existing NOx controls. Natural gas is the primary fuel for each turbine analyzed, except for Metro Wastewater- GDF Suez, which fires primarily digester gas with supplemental natural gas. The Division recommended an analysis for backup fuels only if a turbine's emissions are greater than 1 ton per year due to firing backup fuels. Fuel oil is a common backup fuel; however, combustion of fuel oil in the turbines that were analyzed is so rare that RACT analyses for fuel oil were not necessary or required.

Stationary combustion turbines are typically manufactured in package form with emissions controls accounted for prior to construction, and retrofitted add-on control technologies are sometimes technologically infeasible due to operational or space constraints. Many of the newer turbines analyzed for RACT were equipped with NOx control technologies at the time of construction, depending on the specific needs of the project at the time. Conversely, some of the turbines analyzed were manufactured and installed in the 1970s and no controls were required. Moreover, depending on when a turbine was constructed, it may be subject to a NSPS. The following Table 10 shows the year of construction, associated existing control technologies, and NSPS applicability for each turbine.

Table 10: Stationary Combustion Turbine Existing Controls and Vintage

Facility Name	AIRS ID	Existing NOx Control	Year Installed	NSPS
PSCo- Fort Saint	123-0023-010	DLNB	2009	Subpart KKKK

[13] Generally, the average NOx emissions are based on APEN reported emissions over the period 2014-2016, although some sources do have a CEMS. The three year period could include one APEN report or multiple APEN reports depending source specific reporting schedules.

Facility Name	AIRS ID	Existing NOx Control	Year Installed	NSPS
Vrain	123-0023-011	DLNB	2009	Subpart KKKK
PSCo- Fort Lupton	123-0014-001	None	1972	N/A
	123-0014-002	None	1972	N/A
PSCo- Valmont	013-0001-002	None	1973	N/A
Tri-State- Frank Knutson	001-1349-003	LNB + Water Inj.	2002	Subpart GG
	001-1349-001	LNB + Water Inj.	2002	Subpart GG
Kerr-McGee- Platte Valley	123-0057-052	SoLo NOx	2001	Subpart GG
Wattenberg	001-0025-021/22	SoLo NOx	2003	Subpart GG
PSCo- Cherokee	001-0001-029	DLNB + SCR	2015	Subpart KKKK
	001-0001-028	DLNB + SCR	2015	Subpart KKKK
Metro Waterwater-GDF Suez	001-0097-001-01	None	2000	Subpart GG
	001-0097-001-02	None	2000	Subpart GG

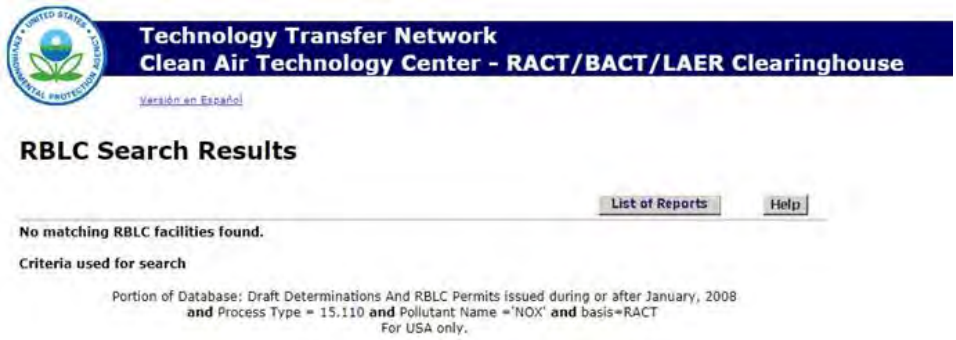
b) Potential NOx Controls

Three-year average capacity factors for each turbine range from ~1% to ~90% depending on the primary reason for operation. Some electric generating turbines are utilized only for peak demand or in the case of a power shortage. Other turbines that were analyzed operate frequently but at low operational capacities. The operational configuration (simple or combined cycle) of the turbines that were analyzed also vary, and therefore, exhaust temperatures differ such that certain emission controls may be technically feasible for one unit but not another. Conventional SCR, for example, requires exhaust temperatures to be at an optimal range to be effective: approximately 450-850 degrees Fahrenheit.[14] Simple cycle combustion turbine exhaust temperatures are typically much higher. SNCR is not considered a technologically feasible option for combustion turbines.[15] The primary control options that were analyzed were dry low NOx burners (**"DLNB"**), selective catalytic reduction, combustion process adjustment and combinations thereof. Technologically infeasible options were eliminated, and technologically feasible options were explored as potential RACT. Based on a review of the RACT analyses, the RBLC clearing house, and permitted RACT in Colorado, SCR and DLNB were determined to be the only technologically feasible NOx control options for any of the turbines that were analyzed. In some cases, those controls have already been installed. DLNB and SCR are not necessarily technologically feasible for every turbine, however. Nevertheless, SCR is an available control technology that is the most effective NOx emission control for turbines when determined to be technically feasible, although it's very high cost generally excludes it from being economically feasible when considered in the context of SIP RACT.

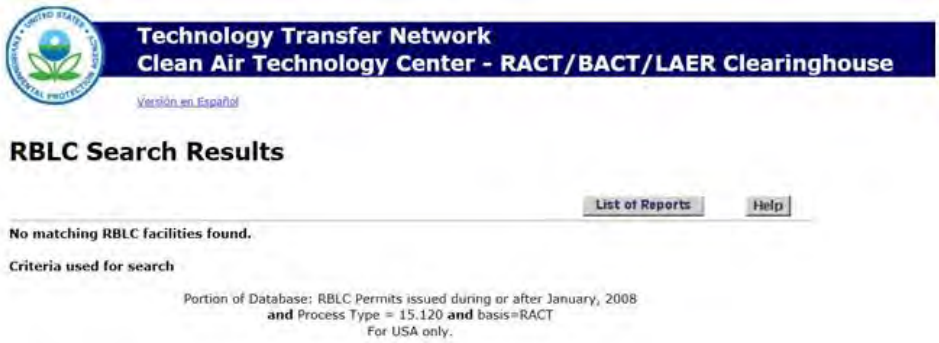
The Division performed a nationwide search of the RBCL database to see if any recent NOx RACT determinations (permitted after 1/1/2008) on turbines could inform an appropriate RACT threshold for turbines. The below screen capture indicates that no RACT determinations are listed for combined-cycle turbines >25 MW. The RBLC standard search used final determinations based on process type code 15.210 - Natural Gas (includes propane and liquefied petroleum gas).

[14] AP-42, 2000
[15] Id.

The below screen capture indicates that no RACT determinations are listed for natural gas fired simple cycle turbines >25 MW. The RBLC standard search used final determinations based on process type code 15.110 – Natural Gas (includes propane and liquefied petroleum gas).



The below screen capture indicates that no RACT determinations are listed for landfill/digester/bio-gas fired simple cycle turbines >25 MW. The RBLC standard search used final determinations based on process type code 15.120 – landfill/digester/bio-gas.



Based on the above RBLC searches for both combined and simple cycle turbines, SCR is not listed as RACT anywhere for turbines, particularly for simple cycle turbines.

c) NOx Control Cost Ranges for Turbines

In all cases, where SCR is not already installed, SCR is either technologically infeasible or cost prohibitive (>$50,000/ton of NOx reduced in some cases). For turbines where digester gas is fired, retrofitted DLNB was determined to be technologically infeasible due to the relatively low heat content of digester gas, which can average as low as 600 btu/scf higher heating

value. Costs were evaluated using allowable emissions and the most recent three-year average of APEN reported emissions[16] over the period of 2014-2016. Only in the case of the three 1970s vintage turbines located at PSCo Valmont and Fort Lupton ("older turbines") was it determined that additional emission control through the use of DLNB is technically and economically feasible when considered on the basis of allowable emissions. All other turbines that were analyzed are equipped with existing LNB technology, with the exception of turbines that fire digester gas. When considering actual emissions, the cost effectiveness of DLNB for the older turbines was greater than $118,000 per ton of NOx reduced. Considering allowable emissions, the estimated cost effectiveness of DLNB for the older "grandfathered" turbines is approximately $390 per ton of NOx reduced.

d) RACT Determination for Turbines

Considering allowable emissions, the Division determined additional NOx control through the use of DLNB is reasonably available and cost effective for the older turbines which are not equipped with NOx control technologies and are grandfathered from NSPS Subparts GG or KKKK applicability. For all other turbines that were analyzed, it was determined that current operational configurations and control strategies constitute RACT. Each turbine that was analyzed is subject to NOx emission limitations set by NSPS Subparts GG or KKKK, with the exception of the older turbines.

To establish appropriate categorical RACT emission limitations for NOx, the Division must consider many critical variables including: maximum design heat input, age, operational configuration, the use of duct burners, fuel type(s), and use. Rather than consider each variable separately in a complex categorical turbine rule, the Division determined that it is most appropriate to incorporate into the regulation by reference the requirements for affected turbines to comply, on a categorical basis, with the emission limits and monitoring requirements established by NSPS Subparts GG and KKKK, which carefully consider each of the aforementioned critical variables. As proposed, turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr must comply with NSPS Subpart GG if constructed on or before February 18, 2005 or NSPS Subpart KKKK if constructed after February 18, 2005. For the older turbines, the Division determined that compliance with NSPS Subpart GG is RACT because doing so would likely require the installation of CEMS and DLNB[17], which is cost effective when considered on the basis of potential to emit (allowable emissions). However, considering the historic limited operation of the older turbines, the Division recognizes that installing controls and CEMS on the older turbines is only cost effective if they were to operate at much higher capacity factors than that of recent historic operation[18]. As described earlier, installing DLNB based on actual emission for 2014 – 2016, would cost > $118,000 per ton of NOx removed. As such, the Division proposes that the older turbines must comply with the emission limits and monitoring requirements of NSPS Subpart GG, only if turbine utilization (capacity factor) becomes greater than the combustion source capacity factor exemption of 20%. Categorical turbine RACT, as proposed, is established in Section XVI.D.4.b in addition to compliance with the existing combustion process adjustment provisions previously established as part of the November 2016 Regulation 7 revisions.

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[16] The Division used APEN reported emissions as a proxy for actual emissions. Actual emissions are likely to be lower than reported emissions because some sources choose to report allowable emissions on the APEN.

[17] Estimated emissions from the older turbines is ~.35 lb/mmbtu (95 ppmvd@15% O2). Compliance with NSPS GG would require meeting an emission limit of ~75 ppmvd@15% O2

[18] See Table 10 for 2014 – 2016 average emissions

Combustion process adjustment is further described in the following section.

e) Combustion Process Adjustment for Turbines

In addition to the categorical RACT provisions proposed in Section XVI.D.4.b., the Division determined that for all stationary combustion turbines that existed at a major source of NOx as of June 3, 2016, with uncontrolled actual emissions of NOx equal to or greater than 5 tons year, RACT includes compliance with the combustion process adjustment requirements which were previously established in Section XVI.D.2 of the 2016 Regulation 7 revisions.[19] Those requirements include the following:

- Inspect turbine inlet systems and align, repair, or replace components as necessary.
- Inspect the combustion chamber components, combustion liners, transition pieces, and fuel nozzle assemblies and clean, repair, or replace components as necessary.
- When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, confirm proper setting and calibration of the combustion controls.

Although the Division identified no turbines with heat input capacities below 10 MMBtu/hr at major sources in the NAA, the proposed rule requires all turbines with NOx emissions greater than 5 tons per year at major sources, including those with heat input capacities below 10 MMBtu/hr, to comply with the combustion process adjustment requirements.

f) Monitoring for Turbines

The Division proposes that turbines subject to the RACT limit should monitor their emissions consistent with the requirements of NSPS GG or KKKK, as applicable. For the older turbines, compliance with NSPS GG would require the installation of CEMS if they do not meet an exemption. All other turbines which are currently subject to NSPS GG or KKKK are already meeting the monitoring requirements of the proposed rule, either through the use of NOx CEMS or performance testing, as applicable.

5) COMPRESSION IGNITION ENGINES

a) Emissions Units Analyzed

The Division reviewed the technical RACT analysis information submitted by the operators of engines located at major stationary sources of NOx located in the DMNFR ozone nonattainment area. Table 11 below provides basic information on each compression ignition engine potentially subject to the RACT review process.

[19] Combustion Process Adjustment, as proposed, is located in Section XVI.D.6.

Table 11: DMNFR Major Stationary Sources – Compression Ignition Engine Information

	Facility Name	Source ID	Year Installed	Engine Rating (Hp)	Avg. NOx Emissions[20] (tons/yr)
1	Buckley AFB	005-0028-104-01	1990	3,353	7.0
		005-0028-104-02	1990	3,353	7.0
		005-0028-104-03	1990	3,353	7.0
		005-0028-104-04	1990	3,353	7.0
		005-0028-104-05	1990	3,353	7.0
		005-0028-104-06	1990	3,353	7.0
		005-0028-104-07	1990	3,353	7.0
		005-0028-104-08	1990	3,353	7.0
		005-0028-104-09	1990	3,353	7.0
		005-0028-104-10	1990	3,353	7.0
2	IBM	013-0006-088-01	1966	100	0.1
		013-0006-088-02	1966	194	0.2
		013-0006-088-03	1977	67	0.1
		013-0006-088-04	1978	120	0.1
		013-0006-088-05	1978	155	0.1
		013-0006-088-06	1986	449	0.4
		013-0006-088-07	1986	1,575	1.4
			1986	1,575	1.4
			1986	1,575	1.4
			1986	1,575	1.4
		013-0006-088-08	1993	2,340	2.0
			1993	2,340	2.0
		013-0006-088-09	1994	2,340	2.0
		013-0006-088-10	1996	2,340	2.0
			1996	2,340	2.0
			1996	2,340	2.0
		013-0006-088-11	1997	1,575	1.4
		013-0006-088-12	1999	166	0.1
		013-0006-088-13	1999	2,498	2.2
		013-0006-090-01	2001	823	0.9
		013-0006-090-02	2008	3,604	3.8
			2008	3,604	3.8
			2008	3,604	3.8
		013-0006-090-03	2003	2,498	2.6
		013-0006-090-04	2001	2,876	3.0
			2001	2,876	3.0

[20] Average NOx emissions based on APEN reported emissions over the period of 2014-2016. The three year period could include one APEN report or multiple APEN reports depending source specific reporting schedule.

b) *Potential NOx Controls for Compression Ignition Engines*

The Buckley Air Force Base ("AFB") engines are "non-emergency engines" that operate as intermittent standby generators during periods of power outage or grid instability to ensure reliable uninterrupted grid power[21] is supplied to support mission critical activities. In addition to evaluating the cost effectiveness of SCR controls, Buckley AFB also provided an evaluation of replacing the above engines with Tier 2, Tier 3 and Tier 4 engines. The Division does not regard engine replacement as an appropriate reasonably available control technology consideration and accordingly did not consider engine replacement in this control cost evaluation.

The IBM engines are emergency electrical generation and fire pump engines that are only operated in emergency situations when electrical power from the local utility is interrupted and for short periods for maintenance checks and readiness testing. The IBM RACT analysis determined that few emission control options exist for emergency generators and that SCR emission controls are not technically feasible for the IBM emergency backup engines. Emergency engines by definition are limited use and are only operated when power is lost or for maintenance or readiness testing.

c) *NOx Control Cost Ranges for Compression Ignition Engines*

Table 12 below lists the average SCR costs that only apply to the Buckley Air Force Base engines, which are not classified as emergency electrical generators.

Table 12: Control Efficiencies and Cost Ranges for Various Engine Emission Control Retrofit Options at Actual Emissions

Control Technology	Estimated % NOx Reduction from Uncontrolled Emissions*	Average of Control Cost ($/ton)
SCR	60-90%	$22,653

**Actual control technology percent reduction is probably lower because many engines already have some level of pre-combustion control.*

The above SCR control costs suggest that SCR controls are very expensive for the Buckley engines based on actual emissions. Evaluating cost effectiveness using actual emissions does provide a sense of the immediate cost impacts to the source but fails to account for potential future emission increases that could change the cost effectiveness of a particular emission control strategy. Consequently, the Division further evaluated each technically feasible emission control based on allowable (permitted) emissions for each compression ignition engine to determine the cost effectiveness, which is listed in Table 13.

Table 13: Control Efficiencies and Cost Ranges for Various Engine Emission Control Retrofit Options at Allowable Emissions

Control Technology	Estimated % NOx Reduction from Uncontrolled Emissions*	Average of Control Cost ($/ton)
SCR	60-90%	$10,256

**Actual control technology percent reduction is probably lower because many engines already have*

[21] The U.S. Department of Defense mission requirement for zero off-line time for the area that these engines support, precludes these engines from falling under the U.S. Environmental Protection Agency (EPA) air rule emergency engine definition.

some level of pre-combustion control.

The above listed average SCR costs for the Buckley AFB engines is based on allowable emissions. Proper operation of an SCR control system requires attaining the optimal temperature (260 ˚C - 540 ˚C) before effective control is achieved. In the situation of intermittent and unpredictable power outages typically experienced at Buckley AFB, attaining SCR operating temperatures could be difficult and may necessitate operation at higher engine loads and extending the operation time. Increasing the generator load and runtime to produce the required temperature necessary for effective operation of add-on SCR controls is counter-productive to the goal of reducing NOx emission in the DMNFR Ozone NAA. Based on the above emission control costs and considering unpredictable transient nature of providing 100% reliable power, SCR emission controls are neither cost effective nor an appropriate consideration for the Buckley compression ignition engines.

d) EPA RBLC Clearinghouse for Compression Ignition Engines

The Division performed a nationwide search of the EPA RACT/BACT/LAER Clearinghouse database to see if any recent (after January 2008) NOx RACT determinations on fuel oil-fired engines could inform an appropriate RACT threshold for compression ignition engines. The below screen capture indicates that no RACT determinations are listed for large engines (>500 hp) firing natural gas. The RBLC standard search used final determinations based on process type code 17.110 - Large Internal Combustion Engines (>500 hp) burning fuel oil (includes ASTM #1 and 2, kerosene, aviation and diesel fuel).

Technology Transfer Network
Clean Air Technology Center - RACT/BACT/LAER Clearinghouse

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Your search has found **1** facilities and **1** processes that match your search criteria. You can view details for one or more facilities by clicking on the highlighted RBLC identifier or the process description in the list below. To create a report, select one of the standard output formats from the list of reports at the bottom of this page. Only facilities that are checked in the table below will be included in your report. Click on the check box next to any facility to switch between checked and unchecked or use the "Check" or "Un-Check" all facilities buttons at the top of the list to check or uncheck all records in the list.

Please note that the use of your browser's BACK button to change the search conditions may result in inaccurate results.

Matching Facilities for Search Criteria : Tips

Portion of Database: RBLC Permits issued during or after January, 2008
and Process Type = 17.110 **and** Pollutant Name ='NOX' **and** basis=RACT

These results are for USA only.

Check | Un-Check | **ALL Facilities** | New Search

NOTE: Draft determinations are marked with a "*" beside the RBLC ID.

RBLC ID	CORPORATE/COMPANY & FACILITY NAME	PROCESS CODE	PROCESS DESCRIPTION	PERMIT NUMBER & PERMIT DATE
Sort By	Sort By			Sort By
☑ NJ-0073	TRIGEN - TRENTON ENERGY CORP TRIGEN	17.110	DUAL FUEL ENGINES ON 100 % DISTILLATE FUEL OIL	BOP 060001 03/08/2008

Check | Un-Check | **ALL Facilities** | Back to Top of Page

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The Trigen facility is subject to a RACT limit established for two Cooper-Bessemer duel fueled engines was 12.0 grams/brake horsepower-hour ("g/bhp-hr"). The engines primarily operate

on natural gas but can operate on distillate during periods of natural gas curtailment. The engine operation on 100% distillate is limited to 200 hours per year. It is unclear whether these engines primarily function as emergency back-up engines, although the generous hour limitation on distillate fuel suggests these engines run more frequently. Nonetheless, the Division concludes that the RBLC provides minimal insight on appropriate RACT thresholds for compression ignition engines.

e) Review of Other States NOx RACT for Compression Ignition Engines

The Division attempted to conduct an extensive review of RACT in other states for "non-emergency and emergency" compression ignition engines", which is listed on Table 14.

Table 14: Other States NOx Limits for Compression Ignition Engines

State	Geographic Applicability	Ozone Region	Engines
			NOx Limit (g/bhp-hr)
CT[1]	Statewide	OTR	8.0
NC[2]	Charlotte – 6 county area	NAA	8.0 (>650 hp but <3,000 hp)
NY[3]	Statewide	OTR	2.3
OH[4]	Cleveland -8 county area	NAA	3.0 (>2,000 hp)
TX[5]	Dallas-Fort Worth	NAA	11.0 (in service before 3/1/2009)
	Houston-Galveston	NAA	11.0 (in service before 10/1/2001)
WI[6]	Milwaukee 7 county area	NAA	8.5 (>2,000 hp)

[1] Based on State of Connecticut Department of Energy and Environmental Protection, Section 22a-174-22e3
[2] Based on North Carolina Department of Environment and Natural Resources Subchapter 2D, Sections 1409 and 1418
[3]Based on Rules and Regulations of the State of New York, Title 6. Chapter III, Subchapter A, Subpart 227-2, RACT for Major Facilities of NOx
[4] Ohio Administrative Code Chapter 3745-110 - NOx RACT
[5] Based on Texas Administrative Code: Title 30. Part 1. Chapter 117. Subchapter B. Division 4. Rule §117.410 and §117.310
[6] Based on Wisconsin Administrative Code, Department of Natural Resources, Chapter NR 428.05(3)(e)4.

The state regulations on the liquid-fueled compression ignition engine category are complex and varied as suggested above. In reviewing the listed state requirements, it appears that RACT for existing compression ignition engines can range from 2.3 to 11.0 g/bhp-hr.

f) RACT Determination for Compression Ignition Engines

In the DMNFR, any major NOx source that has combustion equipment with uncontrolled actual NOx emissions greater than or equal to five tons per year is subject to combustion process adjustment requirements. The CPA requirements adopted in 2016 establish RACT for source subject to Regulation Number 7, Section XVI.D.2 and satisfy the requirements of CAA § 182(b)(2) unless the source is subject to additional RACT requirements under other provisions of Colorado's SIP. Combustion process adjustment specifies that stationary internal combustion engines must be inspected at least annually[22] to ensure that the engine is properly operated and maintained. The owner or operator of a stationary internal combustion engine is required to change the oil and filters as necessary along with inspecting the air cleaners, fuel filters, hoses, and belts and clean and replace as necessary. The owner or operator is also required to keep records of combustion process adjustment activities and

[22] The frequency of inspections could be more frequent depending on whether the emissions unit is subject to a NSPS or NESHAP.

must create a report each year. In addition to the combustion process adjustment requirements for stationary internal combustion engines and based on a review of operator provided information, consideration of the unique mix of compression ignition engines in the DMNFR NAA, other states RACT regulations, EPA NSPS regulations and EPA guidance including the RBLC, the Division proposes to establish a categorical RACT standard of 9.0 g/bhp-hr for compression ignition engines with a maximum design power output greater than or equal to 500 hp.

g) Monitoring and Testing Requirements for Compression Ignition Engines

The proposed categorical RACT standard for compression ignition engines allows for a periodic performance test to demonstrate compliance with the proposed 9.0 g/bhp-hr standard. Although, none of the compression ignition engines analyzed exceed the 20% capacity factor threshold that necessitates compliance with the proposed categorical rule. Consequently, the only known costs associated with monitoring and testing of compression ignition engines are associated with existing combustion process adjustment requirements established in Regulation Number 7, Section XVI.D. If, however, an engine becomes subject to the categorical rule, the performance testing provisions would apply.

6) GLASS MELTING FURNACES

As part of the November 17, 2016 revisions to Regulation 7, the Commission required two container glass manufacturing facilities to submit RACT analyses to the Division by December 31, 2017. At the time, SIP RACT for glass melting furnaces had not been established, and as such, the proposal establishes categorical RACT for glass melting furnaces at major sources of NOx located within the NAA. The categorical RACT is proposed as a production-based emission limit of 1.2 lbs NOx/ton of glass pulled on a 30-day rolling average basis. Because there are only two glass melting facilities that are major sources of NOx in the NAA, this TSD analyzes each facility with more specificity than for other source categories where there is a broader array of sources within given category, such as for boilers, turbines, and compression ignition RICE.

a) Emission Units Analyzed

Glass melting furnace is defined in the proposed rule as "an emissions unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass". The Division reviewed RACT analyses for five (5) glass melting furnaces at two (2) major sources of NOx located within the DMNFR NAA: Owen's Brockway Glass Container Inc. (AIRS ID 123-4406) and Rocky Mountain Bottle Company (AIRS ID 059-0008).

Owens Brockway Glass Container ("Owens") is comprised of two (2) natural gas-fired glass melting furnaces (Furnaces 1 and 2) with a combined production capacity of 313,900 tons of glass pulled per year (approximately 869 tons per day). Each furnace is equipped LNB (Model Cleanfire HRi), oxyfuel-firing, and electric boost, which together reduce NOx emissions to approximately 1.24 lbs NOx per ton of glass pulled.

Rocky Mountain Bottle Company ("RMBC") is comprised of three (3) natural gas-fired glass melting furnaces (Furnaces A, B, and C) with a combined production capacity of 365,000 tons

of glass pulled per year (approximately 1,000 tons per day). Furnaces A, B, and C are each equipped with electric boost for NOx reduction. Furnace C is equipped with over-fire air and oxyfuel, which further reduce NOx emissions. The emissions of all three furnaces are routed to a combined stack. RMBC is operating under a Consent Decree ("CD") which requires Furnace A to be removed from service by March 31, 2019. The CD further requires Furnace B to operate using oxyfuel no later than March 31, 2019. Under the CD, combined emissions from Furnaces B and C will be limited to 1.1 lbs NOx per ton of glass pulled by March 31, 2019.

b) Potential NOx Controls and Costs for Glass Melt Furnaces

NOx control options for glass melting furnaces include process modifications, combustion modifications, and post-combustion control. SCR is a technically feasible post-combustion control option for glass melting furnaces, but it is often problematic for retrofit due to space constraints at older facilities. According to EPA, SCR control efficiencies are around 75%.[23] Oxyfuel-firing involves replacing combustion air with nearly pure oxygen, which reduces the amount of nitrogen available to form thermal NOx. According to EPA, oxyfuel firing is the most effective control option, with NOx control efficiencies around 85%.[24] For the Cross State Air Pollution Rule, EPA determined oxyfuel-firing was the most cost effective control option, with an average cost effectiveness of around $7,481 per ton of NOx reduced.[25] LNB is also a technically feasible control option, with control efficiencies between 30% and 66%.[26] Other process modifications, including cullet preheat, were evaluated and determined to be cost-prohibitive (>$700,000 per ton of NOx reduced for Owens).

c) RACT Determination for Glass Melt Furnaces

The Division reviewed information from EPA, various container glass manufacturing CDs (including RMBC's CD), the RACT analyses submitted in response to the 2016 Regulation 7 revisions, and other state SIPs and proposes a categorical RACT limit of 1.2 lbs NOx per ton of glass pulled on a 30-day rolling average basis. EPA estimates uncontrolled NOx emissions for container glass manufacturing to be 10 lbs per ton of glass pulled.[27] The Division proposed limit represents an approximate 88% control efficiency. Meeting the proposed limit is feasible at Owens and RMBC through the use of a combination of oxyfuel-firing, electric boost, and LNB (at Owens).

For comparison, Wisconsin's categorical RACT limit is 2.0 lbs NOx per ton of glass pulled.[28] Although the Division's proposed limit is more stringent than RACT determined in Wisconsin, the Division determined that for Colorado's glass melting furnaces, a more stringent limit is appropriate given existing furnace configurations and regulatory requirements that are to be imposed through a federal CD at RMBC. Limits resulting from other CDs alleging New Source Review violations at container glass manufacturers in the U.S. are shown below for reference.

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[23] EPA (1994). *Alternative Control Techniques Document – NOx Emissions from Glass Manufacturing*
[24] Id.
[25] EPA (2015). *Assessment of Non-EGU NOx Emission Controls, and Time for Compliance,* Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Docket ID No. EPA-HQ-OAR-2015-0500
[26] EPA (1994). *Alternative Control Techniques Document – NOx Emissions from Glass Manufacturing*
[27] Id.
[28] See WI A.C. Chapter NR 428.20, Register August 2009 No. 644

- Saint-Gobain Containers, 1.3 lb/ton (EPA, January 2010)
- Durand Glass Manufacturing, 1.2 lbs/ton (EPA, September 2012)
- Owens-Brockway, 1.2 lbs/ton (EPA, December 2012)

The Division expects RMBC to be able to meet the proposed RACT limit given the requirements of its CD, as described in Section 4.a. above. It is possible that Owens will need to upgrade their existing HRi LNB to HRx LNB to meet this emission limit. According to Owen's RACT analysis, such an upgrade has an annualized cost of $3,115 per ton of NOx reduced over a 15-year lifespan.

d) Startup and Shutdown Considerations

Glass melting furnaces operate nearly 100% of the time, given the cost and time constraints of shutting down large container glass melting furnaces. However, there are rare times during startup and shutdown due to furnace maintenance where the furnaces must remain warm with low or no production. In recognition that meeting a normal operation production-based limit is not feasible during such times, EPA typically allows emissions from abnormally low production rate days (defined as "any operating day where glass production …is at or below 35% of permitted…or design production…as determined on a daily basis")[29] to be excluded from the compliance period (in the case of the Division's proposed RACT limit: 30-day rolling average). The Division proposes to be consistent with this approach.

e) Monitoring for Glass Melt Furnaces

Compliance with the proposed RACT limit shall be monitored using a continuous emission rate monitoring system ("CERMS"). All furnaces at RMBC and Owens are equipped with NOx CERMS. Where emissions from multiple furnaces are routed to a common stack, as is the case for RMBC, total emissions from all furnaces shall be divided by the total production from all furnaces over the same time period for comparison to the proposed RACT limit.

7) AGGREGATE KILNS

As part of the November 17, 2016 revisions to Regulation 7, the Commission required the one lightweight aggregate manufacturing facility to submit a RACT analysis to the Division by December 31, 2017. At the time, SIP RACT for lightweight aggregate/shale kilns had not been established, and as such, the proposal establishes categorical RACT for lightweight aggregate kilns at major sources of NOx located within the NAA. The proposed categorical RACT emission limit is 56.6 lbs NOx per hour on a 30-day rolling average basis. Because there is only one lightweight aggregate kiln at a major sources of NOx in the NAA, this section analyzes that facility with more specificity than for other source categories where there is a broader array of sources within given category, such as for boilers, turbines, and compression ignition RICE.

a) Emission Units Analyzed

Lightweight aggregate is defined in the proposed rule as "the expanded, porous product from heating shales, clays, slates, slags, or other natural materials in a kiln", and kiln is defined as

[29] See Case 1:17-cv-01554, p. 5

"the equipment used to remove combined (chemically bound) water and/or gases from mineral material through direct or indirect heating". The Division reviewed the RACT analysis for the lightweight aggregate kiln in the DMNFR NAA. Trinity Construction Materials (AIRS ID 059-0409 formerly owned and operated by TXI) operates the lightweight aggregate rotary shale kiln rated at 100 MMBtu/hr, which fires both coal and natural gas. The kiln falls into the category of a long dry kiln that is 240 feet in length and 12 feet in diameter.

b) Potential NOx Controls and Costs for Aggregate Kilns

Lightweight aggregate shale kilns are different from cement kilns, but some of the control strategies used for the cement industry are transferrable to the lightweight aggregate industry. For number of technical reasons, many control options for cement kilns are not always transferable to lightweight aggregate shale kilns. Most of the NOx control options that were analyzed were deemed technologically infeasible. SCR, SNCR, Biosolids injection, tire derived fuel (fuel switch), CemStar Process change, and mid-kiln firing were determined to be technologically infeasible at the Trinity plant. The retrofit installation of LNB for gas-firing was determined to be a technologically feasible NOx control option, but when considering the actual historic firing of coal as the primary fuel at the facility, LNB is cost prohibitive.

The Division obtained cost information for a proposal to install a LNB retrofit on a smaller but similar lightweight aggregate kiln located in California. The vendor guaranteed a 10% emission reduction. Using this cost data, it was determined that the cost effectiveness of the control ranged from $5,279 – $11,824 per ton of NOx reduced, depending on how much gas is fired in a given year. The lower end of the range assumes an annual 56% NOx emissions contribution from natural gas firing, which was the average annual contribution of NOx emissions from natural gas firing from 2013 – 2017. The higher end of the range assumes an annual 33% NOx emissions contribution from natural gas firing, which was the lowest annual contribution from 2013 – 2017. Considering historic fuel use, potential emissions reductions from LNB range from ~6 tons per year to ~14 tons per year, depending on how much natural gas is fired in a given year.

c) RACT Determination for Aggregate Kilns

The Division determined that retrofit emission controls are not cost effective and the existing kiln configuration and good combustion practices constitute RACT for lightweight aggregate kilns. Currently, Trinity is allowed by their Operating Permit to fire 100% coal or 100% natural gas, thus the Division had to consider an appropriate short term RACT limit for multiple fuels. Currently, the facility is only required to track NOx emissions on a 12-month rolling basis using fuel-based emission factors, which do not take potential emissions from the heating of raw materials into account. The Division's proposal requires the facility to conform to their existing synthetic minor Prevention of Significant Deterioration limit on a 30-day rolling average basis using a continuous emission rate monitoring system ("CERMS"). A review of the most recent performance test results shows that achieving a maximum NOx emission rate of 56.6 lbs/hr on a 30-day rolling average basis is attainable through the use of good combustion practices and natural gas firing when appropriate to reduce emissions.

Many emission limits set by regulation and by permits for rotary kilns are production-based (i.e. lbs NOx per ton of product). Through a robust stakeholder process, the Division determined that a pounds per hour emission rate is more appropriate than a production based emission limit because the only affected facility in the source category (Trinity) does not

monitor production on a continuous basis due to the existing plant configuration. The installation of a continuous weigh scale at the facility presents technical problems given the extreme heat of the product as it exits the kiln. Therefore, a pounds per hour emission rate limit is most appropriate to preclude the source from the expenditures and technological burdens of monitoring production on a continuous basis. There is a precedent for establishing a pounds per hour emission limit for rotary kilns that is in Colorado's Regional Haze SIP for a cement kiln subject to Best Available Retrofit Technology ("BART") requirements.

d) Monitoring for Aggregate Kilns

The Division determined that the installation of CERMS is necessary for determining compliance with the proposed categorical RACT limit for lightweight aggregate kilns at major sources of NOx. The thermal NOx formation in a kiln is dependent on many variables of which are not entirely predictable, including flame temperature and stabilization. Additionally, since multiple fuels are fired in the Trinity kiln, utilizing a CERMS eliminates any uncertainty of varying emission rates from firing coal or natural gas. Utilizing CERMS also eliminates the uncertainty of NOx emissions which are formed from the off gassing of nitrogen compounds entrained in raw materials. To monitor NOx emissions on a pounds per hour basis, the CERMS will require a stack gas flow rate monitoring system in conjunction with NOx and diluent concentration monitors.

8) CAPACITY FACTOR EXEMPTION

In Section XVI.D.2., the Division is proposing various exemptions from the categorical emission limitations in Section XVI.D.4., the associated compliance demonstration requirements in Section XVI.D.5., and the related recordkeeping and reporting requirements of Sections XVI.D.7.a-f, and XVI.D.8. (as proposed). In Section XVI.D.2.a., the Division is proposing a 20% capacity factor exemption for stationary combustion equipment that in practical terms may only apply to boilers, turbines, and reciprocating internal combustion engines because glass melting furnaces and aggregate kilns are generally run at high capacities for extended periods of time since they are not easily cycled between operation and non-operation. The capacity factor is determined based on the rolling 3-year average of the actual heat input for each calendar year divided by maximum allowable heat input.

The Division is proposing the 20% capacity factor exemption, in part, as a consolidation of a number of limited-use exemptions that were analyzed and considered by the Division to limit the complexity of the categorical rules and adequately accommodate technical and cost concerns for low emitting limited-use equipment. A number of stakeholders requested reasonable exemptions for specific equipment types involving seasonal operation, limited-use, natural gas curtailment, emergency electric generation, provision of replacement capacity during periods of extended primary unit outage for major maintenance, and the lack of manufacturer emission rate guarantees for low capacity units.

Consistent with requirements adopted by other states, some stakeholders requested a seasonal operation exemption for boilers that are primarily operated to provide steam for indoor heating during the cooler seasons (October – April) and would otherwise be subject to the categorical emission limitations and associated monitoring and recordkeeping requirements of the proposal. During the cooler months, ozone levels are typically well below the standard in the DMNFR. The Division concludes that addressing seasonal operation in the

categorical rule is overly complicated and difficult to enforce. Moreover, the DMNFR ozone season is defined at the federal level as year-round. The proposed 20% capacity factor exemption addresses the seasonal-use concerns and provides owners and operators of seasonal use boilers flexibility to operate more, if necessary, during extremely cold winters, given the three-year rolling average.

A number of stakeholders requested a limited-use exemption for infrequently operated boilers, turbines, and engines that would otherwise be subject to the categorical emission limitations and associated monitoring and recordkeeping requirements. Non-seasonal limited-use combustion equipment operate primarily in situations where backup capacity is needed, such as during emergencies, scheduled or unscheduled primary unit outages due to maintenance or breakdown, natural gas curtailment, and accommodating peak loads. At low capacities, controls are often cost prohibitive or technologically infeasible. The Division determined that there are multiple facilities with excess steam capacity that have the ability to shift capacity (and therefore emissions) away from older higher emitting boilers that are not currently configured to comply with the proposed categorical standard. Many of the older boilers are not equipped with CEMS and may require add-on controls to comply with the proposed categorical standard. The shift in capacity to much newer, lower emitting boilers which are already equipped with NOx controls and CEMS will result in a net emissions reduction. The 20% capacity factor exemption provides a secondary compliance option and incentive to facilities that have this ability, and the resulting shift in emissions from high emitting units to low emitting units will result in an overall better environmental benefit than would result from the installation of CEMS or even controls. Based on the Division's analysis and stakeholder input, this shift in behavior is expected to occur at one-third (4 of 12) of the twelve major source boiler-houses.

Lastly, some stakeholders expressed concerns that a few boilers with low historical use (e.g. heat input below 25%) may need to install controls that cannot meet the RACT standard because manufacturer emission rate guarantees usually apply only when the units operate between 25-100% of the boiler maximum continuous rating ("MCR"). Generally, the boiler burners have a limited range of heat input where the manufacturer can guarantee compliance with a specific emission rate. Emissions from boilers operating at heat inputs below 25% MCR are generally classified as startup/shutdown emissions. Thus, if the Division proposed a RACT standard that a particular boiler was unable to meet and the Division did not offer an adequate capacity factor exemption, the operator would need to install controls and operate the boiler at higher capacity factors to ensure the installed controls meet manufacturer guaranteed emission rates in order to comply with the RACT standard. The installation of boiler controls coupled with increasing boiler heat input in order to ensure compliance with a categorical RACT standard seems contrary to the original intent of reducing emissions, thus Division concludes that it is reasonable to allow exclusion of limited-use boilers from RACT, particularly regarding boilers with historically low heat inputs that could not rely on the manufacturer emission rate guarantees if the installation of emission controls are needed in order to comply with RACT. Consequently, the Division proposes that a 20% capacity factor averaged over a 3-year period is reasonable for these limited-use boilers.