Technical Support Document (TSD)
for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Docket ID No. EPA-HQ-OAR-2015-0500

Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance

U.S. Environmental Protection Agency
Office of Air and Radiation
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1 Introduction/Purpose

The purpose of this Technical Support Document (TSD) is to discuss the currently available information on emissions and control measures for sources of NOx other than electric generating units (EGUs). This information provides more detail about why EGUs are the focus of the proposed rulemaking, namely the uncertainty that exists regarding whether significant aggregate NOx mitigation is achievable from non-EGU point sources by the 2017 ozone season, and the fact that the limited available information points to an apparent scarcity of non-EGU reductions that could be accomplished in this timeframe. Notwithstanding these conclusions as regards the 2017 ozone season, the EPA continues to assess the role of NOx emissions from non-EGU sources to downwind nonattainment problems, and welcomes comments on the information in this TSD both as it relates to the current rule and for future use.

This TSD begins by briefly discussing the non-EGU emissions inventories used in this proposed rule, both for the 2011 base year and 2017 future baseline assessed for this proposed rule. The TSD then presents an evaluation of whether non-EGU emissions can be reduced in a cost-effective manner for particular categories. Then, it assesses the available NOx emission reductions from such categories and presents the category-by-category emissions reduction potential. This assessment considers and presents the costs per ton of these reductions, with a focus on technologies that achieve cost-effective reductions within a range of costs similar to that evaluated for EGUs. Finally, the TSD presents estimates of the time required to install and implement the control measures, both for comparison to the 2017 compliance timeframe, and for discussion of installation time should such measures be required in the future.

For the reasons stated in the preamble, the data and discussion in this TSD are intended to focus on the eastern states that are the focus of the Cross-State Air Pollution Rule (CSAPR). Information inclusive of western states[1] is presented where available and appropriate.

[1] For the purpose of this action, the western U.S. (or the West) consists of the 11 western contiguous states of Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Utah, Washington, and Wyoming, and the eastern U.S. (or East) consists of the remaining states in the contiguous U.S.

2 Background

In this section we present annual and ozone-season NOx emission inventory totals and the relative percentages for non-EGU source categories statewide and/or nationally. This information is summary in nature and is not meant to replace other, more detailed information available from the EPA, such as the EPA's 2011v6.2 Emissions Modeling Platform TSD[2] as well as the Notice of Data Availability[3] (NODA) and Regulatory Impact Analysis[4] (RIA) for this proposed rulemaking.

Table 1 lists 2011 and 2017 projected NOx emissions by sector, in summary form, for the 48 contiguous states of the U.S. (CONUS).

Table 1: 2011 Base Year and 2017 Projected NOx Emissions by Sector (tons), for the 48 CONUS

Sector	2011 NO_x, annual	2017 NO_x, annual	2011 NO_x, ozone season	2017 NO_x, ozone season
EGU-point	2,000,000	1,500,000	942,000	689,000
NonEGU-point	1,200,000	1,200,000	515,000	502,000
Point oil and gas	500,000	410,000	213,000	172,000
Wild and prescribed fires	330,000	330,000	165,000	165,000
Nonpoint oil and gas	650,000	690,000	275,000	293,000
Residential wood combustion	34,000	35,000	3,000	3,000
Other nonpoint	760,000	730,000	204,000	211,000
Nonroad	1,600,000	1,100,000	825,000	582,000
Onroad	5,700,000	3,200,000	2,417,000	1,329,000
C3 Commercial marine vessel (CMV)	130,000	130,000	58,000	58,000
Locomotive and C1/C2 CMV	1,100,000	910,000	451,000	384,000
Biogenics	1,000,000	1,000,000	630,000	630,000
TOTAL	**15,000,000**	**11,200,000**	**6,698,000**	**5,018,000**

It is clear from Table 1 that NOx emissions are projected to remain constant or decrease for most sectors in the 48 states between 2011 and 2017. Emissions from the non-EGU point source sector and the other nonpoint source sector are not projected to change significantly, while emissions from the nonpoint oil and gas source sector are projected to grow (approximately 6%), during this time period. Based on the values in Table 1, Figures

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[2] Technical Support Document (TSD), Preparation of Emissions Inventories for the Version 6.2, 2011 Emissions Modeling Platform, August 2015, available at: http://www3.epa.gov/ttn/chief/emch/2011v6/2011v6_2_2017_2025_EmisMod_TSD_aug2015.pdf

[3] Notice of Availability of the Environmental Protection Agency's Updated Ozone Transport Modeling Data for the 2008 Ozone National Ambient Air Quality Standard (NAAQS). The official version is available in the docket for this proposed rulemaking.

[4] Regulatory Impact Analysis for the Proposed Cross-State Air Pollution Rule (CSAPR) for the 2008 Ozone National Ambient Air Quality Standards (NAAQS). The official version is available in the docket for this proposed rulemaking.

1 and 2 show the relative contributions of the various sectors to overall NOx emissions (left panel) and for the non-EGU sectors (right panel) for 2011 and 2017, respectively.

Figure 1: 2011 NOx emissions by sector, with further non-EGU breakout (48 states)

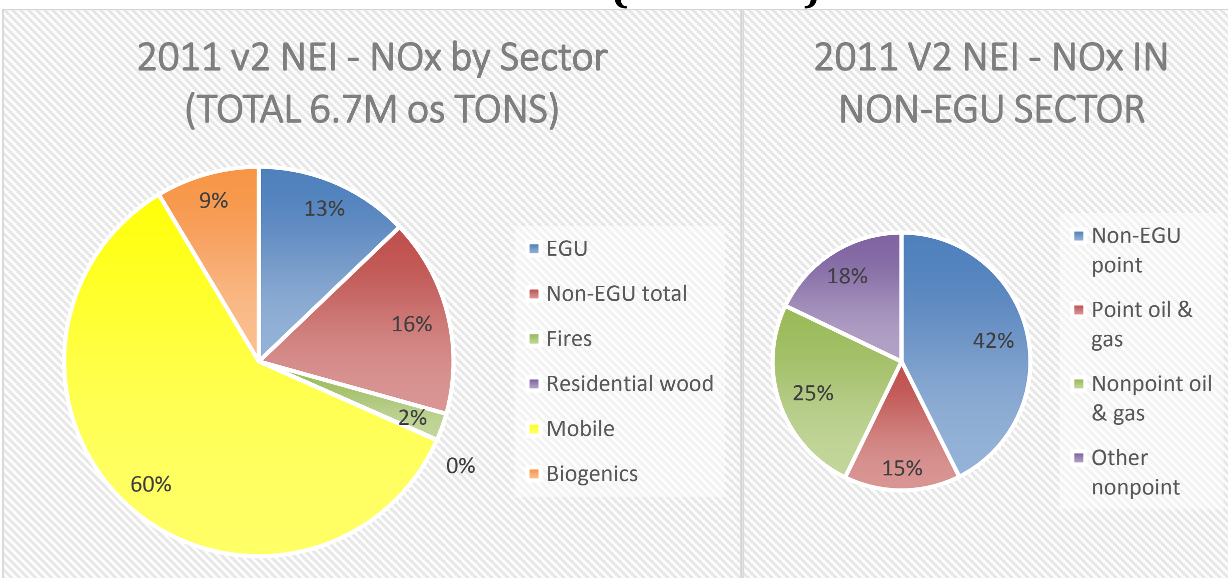

Figure 2: Projected 2017 NOx emissions by sector, with further non-EGU breakout (48 states)

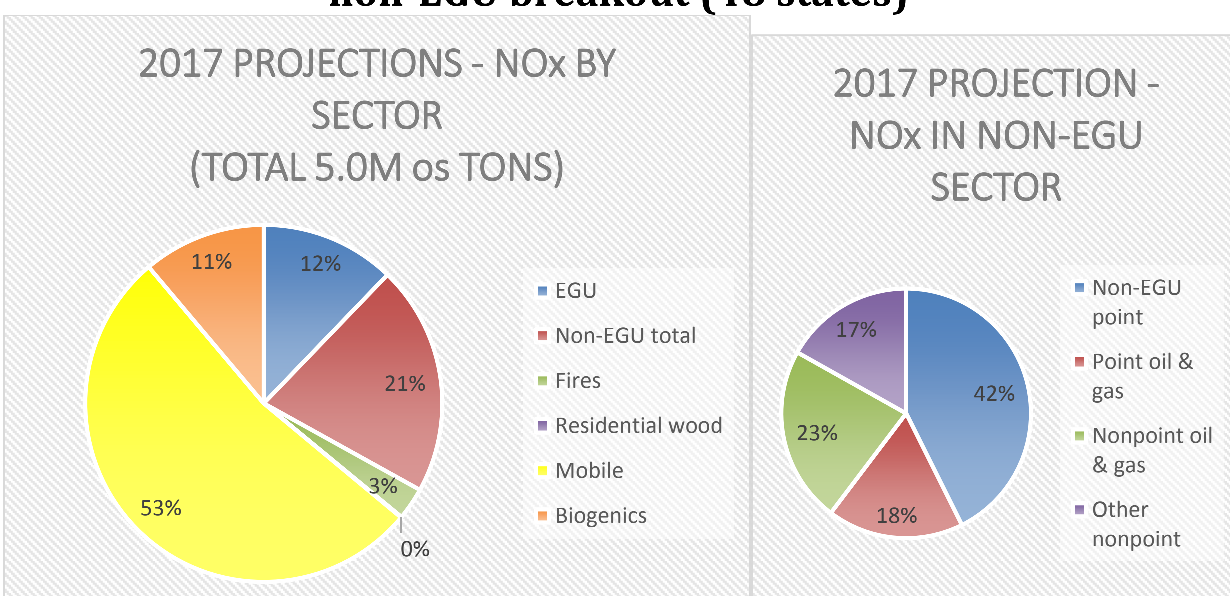

Figure 1 depicts total ozone season NOx emissions of 6,698,000 tons in 2011 and Figure 2 depicts total ozone season NOx emissions of 5,018,000 tons in 2017. In both 2011 and 2017, the mobile source sector has the largest NOx emissions. Substantial reductions in mobile source NOx are projected to occur by 2017. Mobile sources are projected to decrease because of sector-specific standards related to fuels, fuel economy, pollution controls, and repair and replacement of the existing fleet. Because these reductions are already expected to occur, mobile source emission reductions are not included in this analysis of non-EGU emission reductions achievable by the 2017 ozone season.

For the purposes of preliminary analysis in this TSD, "non-EGU total" refers to four separate categories of sources: non-EGU point, point oil and gas, nonpoint oil and gas, and other nonpoint (and does not include mobile sources). The oil and gas point and nonpoint sources are separated from the remaining non-EGU point and nonpoint sources due to the magnitude of their contribution to the inventory and other aspects related to the inventory development, emissions modeling, and future year projections for that industry. The point oil and gas sources are also separated out from the other non-EGU point sources according to the NAICS code specified for the various sources. Note that point oil and gas sources include a variety of types of processes, and there is overlap with the processes included in the rest of the non-EGU point inventory. More information on the emissions sectors is available in the 2011v6.2 Emissions Modeling Platform TSD.

Comparing the proportions of the total inventory for non-EGUs (Figures 1 and 2), it becomes clear that, although they are decreasing in the absolute sense, non-EGU NOx emissions are becoming a larger share of overall ozone-season NOx emissions (16% in 2011 compared with 21% in 2017).

Table 2 compares statewide projected total anthropogenic NOx emissions (inclusive of all sectors listed in Table 1 with the exception of fires and biogenics) for the 2017 ozone season to non-EGU NOx emissions for the 2017 ozone season for each of the 48 contiguous states of the U.S. Totals are given for the 48 contiguous United States (the 37 eastern states plus D.C. that are addressed in the proposed rulemaking are highlighted below in blue). Non-EGU sources in this table are broken down into two groups (non-EGU point sources, including point oil & gas sources, and other nonpoint and nonpoint oil & gas sources).

Table 2: Projected Total Anthropogenic Ozone-Season NOx Emissions vs. Projected Non-EGU Source Group NOx Emissions, 2017 Projections, Tons[5]

State	Total Anthropogenic	Non-EGU Point + Oil & Gas Point	% Anthro	Oil & Gas Nonpoint+ Other Nonpoint	% Anthro	Oil & Gas Point + Oil & Gas Nonpoint	% Anthro
Alabama	88,805	22,187	25	7,952	9	7,442	8
Arizona	71,906	5,015	7	2,310	3	612	1
Arkansas	69,737	13,400	19	5,308	8	9,164	13
California	236,322	29,342	12	20,220	9	3,105	1
Colorado	90,756	19,594	22	16,899	19	27,284	30
Connecticut	17,672	1,105	6	2,626	15	98	1
Delaware	7,786	628	8	615	8	0	0
District of Columbia	2,252	212	9	312	14	0	0
Florida	177,514	16,293	9	7,543	4	1,112	1
Georgia	103,536	18,816	18	4,559	4	1,495	1
Idaho	27,893	3,752	13	1,989	7	503	2
Illinois	148,178	24,668	17	15,409	10	9,424	6
Indiana	139,133	27,222	20	6,864	5	5,931	4
Iowa	70,467	7,888	11	3,861	5	153	0
Kansas	79,939	6,968	9	12,619	16	10,697	13
Kentucky	106,830	11,456	11	11,905	11	12,251	11
Louisiana	173,330	45,506	26	30,160	17	31,503	18
Maine	17,576	4,639	26	809	5	26	0
Maryland	46,029	6,213	13	3,508	8	522	1
Massachusetts	35,369	4,144	12	4,807	14	105	0
Michigan	131,486	21,867	17	12,245	9	9,398	7
Minnesota	89,328	15,541	17	6,414	7	46	0
Mississippi	54,832	11,684	21	2,122	4	6,557	12
Missouri	101,035	9,238	9	3,594	4	122	0
Montana	38,504	2,948	8	3,630	9	3,390	9
Nebraska	70,005	3,884	6	1,163	2	467	1
Nevada	28,192	4,018	14	1,003	4	115	0
New Hampshire	8,932	680	8	1,028	12	0	0
New Jersey	52,743	4,544	9	5,506	10	173	0
New Mexico	65,263	10,559	16	19,940	31	27,759	43
New York	109,910	13,738	12	14,624	13	904	1
North Carolina	98,064	15,711	16	3,657	4	1,203	1
North Dakota	74,118	4,047	5	18,125	24	19,185	26
Ohio	160,110	21,280	13	11,617	7	2,906	2
Oklahoma	131,763	32,203	24	33,178	25	51,257	39
Oregon	40,507	6,130	15	4,348	11	365	1
Pennsylvania	174,664	23,735	14	33,508	19	26,713	15

[5] EGUs are not provided a separate breakout in Table 2 since state-level emissions are presented in the emissions modeling platform TSD and other TSDs for this proposal.

State	Total Anthropogenic	Non-EGU Point + Oil & Gas Point	% Anthro	Oil & Gas Nonpoint+ Other Nonpoint	% Anthro	Oil & Gas Point + Oil & Gas Nonpoint	% Anthro
Rhode Island	5,845	544	9	1,370	23	12	0
South Carolina	55,897	10,144	18	3,980	7	348	1
South Dakota	22,192	1,241	6	432	2	75	0
Tennessee	85,759	13,494	16	5,846	7	1,922	2
Texas	467,245	95,671	20	115,180	25	145,285	31
Tribal Data	26,717	3,799	14	0	0	3,700	14
Utah	66,486	8,004	12	9,781	15	9,349	14
Vermont	5,473	163	3	937	17	0	0
Virginia	87,754	14,039	16	7,318	8	4,775	5
Washington	75,833	8,666	11	1,150	2	164	0
West Virginia	64,839	9,678	15	12,642	19	16,723	26
Wisconsin	75,047	11,181	15	5,351	7	178	0
Wyoming	68,864	26,488	38	4,018	6	10,905	16
Eastern States	***3,411,193***	***545,649***	***16***	***418,692***	***12***	***378,171***	***11***
US Total	***4,248,436***	***673,964***	***16***	***503,980***	***12***	***465,421***	***11***

Table 2 indicates that, in the projected 2017 inventory, non-EGU sources comprising non-EGU point and point oil and gas sources are estimated to make up 16% of anthropogenic NOx emissions in the 48 contiguous United States. In individual states, the percentage of anthropogenic emissions contributed by these two non-EGUs categories range from 3% to 26% (eastern states) and from 7% to 38% (western states).

We also note that in the projected 2017 inventory, non-EGU sources comprising nonpoint oil & gas and other nonpoint sources are estimated to make up 12% of anthropogenic NOx emissions in the entire continental U.S. In individual states, the percentage of anthropogenic emissions contributed by these non-EGUs ranges from 2% to 25% (eastern states) and from 4% to 31% (western states).

The EPA's preliminary analysis indicates that NOx emissions from oil and gas sources (inclusive of emissions from the point oil and gas and nonpoint oil and gas sectors) comprise an average of 11% of the total ozone season NOx emissions inventory. For some states, this percentage increases up to 43%, with oil and gas emissions exceeding non-EGU point totals in a number of states. The key sources of NOx emissions in the oil and gas sector are from the combustion of fossil fuel (primarily drilling rigs, internal combustion (IC) engines and pipeline compressors) and flares. Please refer to the EPA's 2011v6.2 Emissions Modeling Platform TSD for more information on emissions from these sectors.

3 Preliminary Analysis

For the purposes of this proposed rule, the EPA performed a preliminary analysis to characterize whether there are non-EGU source groups with a substantial amount of available cost-effective NOx reductions achievable by the 2017 ozone season.

3.1 Methodology

The EPA's preliminary analysis of potential non-EGU NOx emission reductions was performed using the Control Strategy Tool (CoST). CoST is the software tool the EPA uses to estimate the emission reductions and costs associated with future-year control strategies, and then to generate emission inventories that result from the control strategies applied. CoST tracks information about control measures, their costs, and the types of emissions sources to which they apply. The purpose of CoST is to support national- and regional-scale multi-pollutant analyses, primarily for Regulatory Impact Analyses (RIAs) of the National Ambient Air Quality Standards (NAAQS). CoST is also a component of the Emissions Modeling Framework (EMF) that was used to generate the 2017 non-EGU emissions presented above and in the Emissions Modeling Platform TSD for this proposal. Further discussion and documentation of CoST is available on the EPA's website at http://www.epa.gov/ttnecas1/cost.htm.

Appendices to this TSD discuss recommendations for updates to CoST, including corrections for inapplicable controls, sources already controlled by state rules, sources with permit limits or that clearly identified controls in place, and sources subject to future NOx emission limits. Appendix A summaries RTI's work to review estimates for lean burn IC engines, glass manufacturing, ammonia reformers, and gas turbines.[6] Appendix B discusses SRA's work on a variety of other categories including many of the others evaluated in this TSD.[7]

It should be noted that all of the NOx measures included in this report are currently in the Control Measure Data Base (CMDB) used by CoST, and do not reflect the updates suggested in these contractor reports. Obstacles to full incorporation of the recommended changes include availability of accurate costs for these measures, and to have cost equations rather than average cost/ton to estimate costs. Control efficiencies are readily available for measures, but costs, particularly those that can be estimated using equations that consider source size or capacity, often are not. The EPA plans to incorporate these recommendations for changes or additions to the NOx controls for non-EGUs to support NOx control efforts for future rules and other efforts. Nonetheless, the information from these reports helped inform our assessment in terms of uncertainty surrounding non-EGU emission reduction potential. Further details on the CMDB can be found on the CoST web site.

For the purpose of identifying a list of non-EGU NOx source groups with controls available, the EPA ran CoST including non-EGU sources for the 37 eastern U.S. with NOx emissions of greater than 25 tons/year in 2017. These reports are included in the Appendices of this TSD. Through a contractual agreement with EPA, SRA International and RTI International provided reports which CoST examined a number of source categories of non-EGUs with control costs up to $10,000 per ton (in 2011 dollars). CoST selected particular control

[6] "Update of NOx Control Measure Data in the CoST Control Measure Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines," Revised Draft Report, RTI International, 2014.

[7] "Review of CoST Model Emission Reduction Estimates," SRA International, 2014; "Summary of State NOx Regulations for Selected Stationary Sources," SRA International, 2014.

technologies based on application of a least-cost criterion for control measures applied as part of control strategy. Other NOx control measures are available for some of these categories, but on average annualized costs for these measures were at higher cost.

3.2 Uncertainties and Limitations

The EPA acknowledges several important limitations of the non-EGU cost analysis included in this TSD, which include the following:

Boundary of the cost analysis: In this engineering cost analysis we include only the impacts to the regulated industry, such as the costs for purchase, installation, operation, and maintenance of control equipment over the lifetime of the equipment. Recordkeeping, reporting, testing and monitoring costs are not included. Additional profit or income may be generated by industries supplying the regulated industry, especially for control equipment manufacturers, distributors, or service providers. These types of secondary impacts are not included in this cost analysis.

Cost and effectiveness of control measures: Our application of control measures reflect nationwide average retrofit factors and equipment lives. We do not account for regional or local variation in capital and annual cost items such as energy, labor, materials, and others. Our estimates of control measure costs may over- or under-estimate the costs depending on how the difficulty of actual retrofitting and equipment life compares with our control assumptions. In addition, our estimates of control efficiencies for control measures included in our analysis assume that the control devices are properly installed and maintained. There is also variability in scale of application that is difficult to reflect for small area sources of emissions.

Discount (Interest) rate: Because we obtain control cost data from many sources, we are not always able to obtain consistent data across original data sources. If disaggregated control cost data are not available (i.e., where capital, equipment life value, and operation and maintenance [O&M] costs are not shown separately), the EPA assumes that the estimated control costs are annualized using a 7 percent discount rate, which is the discount (interest) rate used in accordance with OMB guidance in Circular A-94. In general, we have some disaggregated data available for non-EGU point source controls. In addition, while these interest rates are consistent with OMB guidance, the actual interest rates may vary regionally or locally.

Accuracy of control costs: We estimate that there is an accuracy range of +/- 30 percent for non-EGU point source control costs. This level of accuracy is described in the EPA Air Pollution Control Cost Manual, which is a basis for the estimation of non-EGU control cost estimates included in this TSD. This level of accuracy is consistent with either the budget or bid/tender level of cost estimation as defined by the AACE International. In addition, the accuracy of costs is also influenced by the availability of data underlying the cost estimates for individual control measures. For some control measures, we recognize that there is limited data available to generate robust cost estimates. This is reflected in the derivation of costs for some of the non-EGU NOx control measures discussed in Appendix A for this TSD.

3.3 CoST Results

The results of the CoST analysis are displayed in Table 3. In this table, we display the source groups selected by CoST, the Source Classification Codes (SCCs) included in those groups[8], the least-cost control technology for a given source group (also selected by CoST), the current estimate (in dollars per ton, using 2011 dollars) of the annualized cost per ton NOx reduced of the control technology, the current estimate of the time necessary to install the selected control technology (not including permitting time), the estimated ozone season emissions in the East from the non-EGU source group in 2017 in the absence of the installation of the selected controls, and the estimated potential ozone season reductions in the East from the non-EGU source group in 2017 assuming the selected controls could be fully installed and operational prior to the 2017 ozone season (which as discussed in more detail later, is not the case for many of the categories examined). Note that CoST does not account for installation time or time required for the permitting process. Instead it provides information on the control measures applicable to sources in the inventory, along with the cost of installation and operation of the selected measures.

[8] The CoST results do not indicate applicability of the recommended control technology to all sources in the source group but only to the specific SCCs for which control technologies are applicable. For example, for the cement kilns source group, BSI is applicable only for the types of cement kilns covered by the listed SCCs.

Table 3: CoST Results: Non-EGU Source Groups with NOx Reductions

Non-EGU Source Group	SCCs	Control Technology Recommended by CoST	Current estimate of NOx $/ton, CoST (2011 $)	Time to install[9] [10](excluding permitting, reporting preparation, programmatic and administrative considerations[11])	2017[12] NOx Emissions (37 States + DC), OS tons, CoST	2017 Potential Reductions[13] (37 States + DC), OS tons, CoST
Cement Kilns	30500622 (preheater kiln), 30500623 (preheater/precalciner); 39000201 (kiln/dryer); 39000288 (kiln in process coal)	Biosolid Injection Technology (BSI)	$410	Uncertain	24,760	4,207
Cement Mfg (dry)	30500606 Industrial Processes, Mineral Products, Cement Manufacturing (Dry Process), Kilns	Selective Non-Catalytic Reduction (SNCR)	$1,255	42-51 weeks	13,006	6,501
Cement Mfg (wet)	30500706 Industrial processes, mineral products, Cement Manufacturing (Wet Process), Kilns	Mid-Kiln Firing	$73	5-7 months	7,971	2,287

[9] Time to install is not an output of CoST, but are rather estimates determined by EPA based on research from a variety of sources. See "Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources," Institute of Clean Air Companies, December 2006 (all sources except cement kilns and RICE), "Cement Kilns Technical Support Document for the NOx FIP," EPA, January 2001 (cement kilns), and "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry," Innovative Environmental Solutions Inc., July 2014 (prepared for the INGAA Foundation).

[10] In general, for control retrofits to non-EGU sectors, it appears that the full sector-wide compliance time is uncertain, but is longer than the installation time shown above for a typical unit. We have insufficient information on capacity and experience within the OEM suppliers and major engineering firms supply chain to offer conclusions on their availability to execute the project work for non-EGU sectors.

[11] Non-EGUs of any type – boiler or turbine – that are not currently required to monitor and report in accordance with 40 CFR Part 75 and/or not currently participating in the existing CSAPR program will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting and/or participating in the current CSAPR program. Installation of NOx monitors for the reporting of NOx mass requires the construction of platforms, CEM shelters, procurement of equipment, certification testing, and electronic data reporting programming of a data handling system. These added timing considerations for infrastructure on the non-EGU sources combined with the additional programmatic adoption measures necessary make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

[12] Emissions and potential reductions for Gas Turbines ($163/ton grouping), Cement Kiln/Dryer (Bituminous Coal) ($942/ton grouping), Coal Cleaning – Thermal Dryer (2), Spreader Strokers, Petroleum Refinery Process Heaters, Incinerators, Boilers & Process Heaters, Gas-Fired Process Heaters, Coal Boilers, By-Product Coke Manufacturing, ICI Boilers – Residual Oil, Ammonia Production, Glass Manufacturing, ICI Boilers, Iron & Steel - In-Process Combustion - Bituminous Coal, Industrial Processes Miscellaneous, Catalytic Cracking, Process Heaters, & Coke Ovens, Petroleum Refinery Gas-Fired Process Heaters, Glass Manufacturing – Pressed, Glass Manufacturing – Container, Petroleum Refinery Gas-Fired Process Heaters, and RICE source groups were calculated for 2018, however they are likely to be virtually identical to projections for 2017. Non-EGU source groups with projected aggregate 2017 NOx emissions below 100 OS tons are excluded from this table.

[13] Potential reductions assume fully implemented controls by the start of the 2017 ozone season.

Coal Cleaning – Thermal Dryer (1)	30502508 Construction Sand & Gravel, Dryer; 30501001 Industrial Processes, Mineral Products, Coal Mining, Cleaning, and Material Handling, Fluidized Bed Reactor	Low NOx Burner (LNB)	$1,125	6-8 months	503	165
Coal Cleaning – Thermal Dryer (2)	30501001 Industrial Processes, Mineral Products, Coal Mining, Cleaning, and Material Handling, Fluidized Bed Reactor	Low NOx Burner (LNB)	$1,640	6-8 months	154	63
Cement Kiln/Dryer (Bituminous Coal)	39000201 Industrial Processes, In-process Fuel Use, Bituminous Coal, Cement Kiln/Dryer (Bituminous Coal)	SNCR	$942	42-51 weeks	520	260
Iron and Steel Mills - Reheating	30300934 (303015) Primary Metal Production: Steel; 30300933	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	$620	6-8 months	1,064	664
Steel Production	30490033 Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Natural Gas: Furnaces; 30400704 Industrial Processes, Secondary Metal Production, Steel Foundries, Heat Treating Furnace	Low NOx Burner (LNB)	$928	6-8 months	281	141
Nitric Acid Mfg	30101301 Chemical Manufacturing, Nitric Acid, Absorber Tail Gas (Pre-1970 Facilities); 30101302 Chemical Manufacturing, Nitric Acid, Absorber Tail Gas (Post-1970 Facilities)	NSCR	$900	6-14 weeks	1,290	724
Petroleum Refinery Process Heaters	30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$940-$1101	28-58 weeks	179	177
Gas Turbines	20200201 Natural Gas, Turbine; 20200203 Natural Gas, Turbine: Cogeneration; 20300202 Natural Gas, Turbine	Low NOx Burner (LNB)	$163	12 months	945	793
Gas Turbines	20200201 Natural Gas, Turbine; 20200203 Natural Gas, Turbine: Cogeneration; 20300202 Natural Gas, Turbine; 20300203 Natural Gas, Turbine: Cogeneration	Low NOx Burner (LNB)	$800	6-8 months	16,036	4,713
Natural Gas RICE Pipeline Compressors	20200202 Internal Combustion Engines, Industrial, Natural Gas, Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	$249	Uncertain	10,099	2,958

Natural Gas RICE Miscellaneous	20100202 Internal Combustion Engines, Electric Generation, Natural Gas, Reciprocating; 20200202 Internal Combustion Engines, Industrial, Natural Gas, Reciprocating; 20200204, Internal Combustion Engines, Industrial, Natural Gas, Reciprocating: Cogeneration; 20300201, Internal Combustion Engines, Commercial/Institutional, Natural Gas, Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	$447	Uncertain	27,600	8,085
Natural Gas RICE Pipeline Compressors, Rich Burn	20200253 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Rich Burn	NSCR	$517	Uncertain	11,758	10,571
Natural Gas RICE Pipeline Compressors, Lean Burn / Clean Burn	20200252 Internal Combustion Engines, Industrial, Natural Gas, 2-cycle Lean Burn; 20200254 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Lean Burn; 20200255 Internal Combustion Engines, Industrial, Natural Gas, 2-cycle Clean Burn; 20200256 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Clean Burn	Low Emission Combustion (LEC)	$649	Uncertain	47,321	41,169
Diesel / Dual Fuel RICE	20200401 Internal Combustion Engines, Industrial, Large Bore Engine, Diesel; 20200402 Internal Combustion Engines, Industrial, Large Bore Engine, Dual Fuel (Oil/Gas)	Ignition Retard	$1,255	Uncertain	865	216
Catalytic Cracking (1)	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	$1,375	6-8 months	255	140
Spreader Strokers	10100204 External Combustion Boilers, Electric Generation, Bituminous/Subbituminous Coal, Spreader Stroker (Bituminous Coal)	SNCR	$1,390	42-51 weeks	394	158
Petroleum Refinery Process Heaters	30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$1,406-$1,501	28-58 weeks	161	157

Incinerators	50200102, 50200103, 50200104, 50200504, 30190013, 30190014, 50300101, 50300106, 50300112, 50300113, 50300501, 50300503, 50300504, 50300599, 50100101, 50100102, 50100103, 50100506, 50100515, 50100516, 39990024 Incineration	SNCR	$1,842	42-51 weeks	6,556	2,950
Boilers & Process Heaters	10200203, 10200217, 10300216, 10200204, 10200205, 10300207, 10300209, 10200799 External Combustion Boilers; 30190002, 30600103 Industrial Process Heaters	SCR	$2,235	28-58 weeks	13,146	10,358
Natural Gas RICE Electric Generation	20100206 Internal Combustion Engines, Electric Generation, Natural Gas, Reciprocating: Evaporative Losses (Fuel Delivery System)	Adjust Air to Fuel Ratio and Ignition Retard	$2,347	Uncertain	107	32
Catalytic Cracking (2)	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit; 30600202 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Catalyst Handling System	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	$2,369	6-8 months	274	97
Gas-Fired Process Heaters (1)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired	SCR-95%	$2,376	28-58 weeks	211	204
Coal Boilers	10200206, 10200224, 10200225, 10300102, 10300208, 10300224, 10300225	SNCR	$2,413	42-51 weeks	1099	495
Gas-Fired Process Heaters (2)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas Fired	Ultra-Low NOx Burners	$2,419-$2,638	6-8 months	137	64
By-Product Coke Manufacturing	30300306 Industrial Processes, Primary Metal Production, By-Product Coke Manufacturing, Oven Underfiring	SNCR	$2,673	42-51 weeks	2,366	1,420
ICI Boilers – Residual Oil	10200401, 10200402, 10200404, 10300401, 10300402 External Combustion Boilers, Residual Oil	LNB & SNCR	$2,850	6-8 months	991	689
Ammonia Production	30100306 Industrial Processes, Chemical Manufacturing, Ammonia Production, Primary Reformer: Natural Gas Fired	SCR	$2,896	28-58 weeks	2,508	2,257
Glass Manufacturing - Flat	30501403 Industrial Processes, Mineral Products, Glass Manufacture, Flat Glass: Melting Furnace	OXY-Firing	$3,097	Uncertain	9,721	7,880

ICI Boilers	10200201, 10200202, 10200212, 10300205, 10200501, 10200504, 10200601, 10200602, 10200603, 10200604, 10201401, 10300601, 10300602, 10200701, 10200704, 10200707, 10201402 External Combustion Boilers	Low NOx Burner & SCR	$3,456	6-8 months (LNB) 28-58 weeks (SCR)	31,005	28,204
Iron & Steel - In-Process Combustion - Bituminous Coal	30300819, 30300824, 30300913, 30300914, 30301522 Industrial Processes, Primary Metal Production	SCR	$3,705	28-58 weeks	829	746
Diesel RICE Miscellaneous	20100102 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating; 20100107 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating: Exhaust; 20200102 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating; 20200106 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating: Evaporative Losses (Fuel Storage and Delivery System); 20200107 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating: Exhaust; 20300101 Internal Combustion Engines, Commercial/Institutional, Distillate Oil (Diesel), Reciprocating; 20400403 Internal Combustion Engines, Engine Testing, Reciprocating Engine, Distillate Oil	SCR	$3,814	28-58 weeks	1,091	869
Catalytic Cracking, Process Heaters, & Coke Ovens	30600201, 30390004, 39000701, 39000702, 39000797	LNB & FGR	$5,199	6-8 months	1,989	1,094
Petroleum Refinery Gas-Fired Process Heaters (3)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired, 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$8,885-$9,140	28-58 weeks	370	316
Glass Manufacturing - Pressed	30501404 Industrial Processes, Mineral Products, Glass Manufacture, Pressed and Blown Glass: Melting Furnace	OXY-Firing	$6,356	Uncertain	1,001	851

Petroleum Refinery Gas-Fired Process Heaters (2)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired, 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$7,533-$8,120	28-58 weeks	362	304
Industrial Processes Miscellaneous	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit; 39000701 Industrial Processes, In-process Fuel Use, Process Gas, Coke Oven or Blast Furnace	LNB & FGR	$4,026	6-8 months	871	479
Glass Manufacturing - Container	30501402 Industrial Processes, Mineral Products, Glass Manufacture, Container Glass: Melting Furnace	OXY-Firing	$7,481	Uncertain	3,107	2,628
Petroleum Refinery Gas-Fired Process Heaters (1)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired; 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$5,609-$5,884	28-58 weeks	372	338
Taconite Ore Processing	30302351, 30302352, 30302359 Industrial Processes, Primary Metal Production, Taconite Ore Processing, Induration	SCR	$6,449	28-58 weeks	1,188	991
Diesel RICE Electric Generation	20200102 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating	SCR	$1,499	28-58 weeks	778	622

3.4 Discussion of Non-EGU Source Groups

The below discussion utilizes the information in Table 3 in order to assess whether significant aggregate NOx mitigation is achievable from non-EGU sources by the 2017 ozone season.

It is clear that a number of source categories have been identified by CoST that have the potential for non-EGU stationary source emissions reductions. There are some notable source categories below $10,000 per ton that have the potential for substantial non-EGU stationary source emissions reductions. However, for the purposes of this analysis, the EPA did not further examine control options above $3,300 per ton. This is consistent with the range we analyzed for EGUs in this proposal, and is also consistent with what the EPA has identified in previous transport rules as highly cost-effective, including the NOx SIP call.[14] Again, this was done because the objective of this analysis is to characterize whether significant aggregate NOx mitigation is achievable from non-EGU sources by the 2017 ozone season, so we focused the search on categories with highly cost-effective technologies. This focus excludes several source groups with high reduction potential, including as SCR & LNB from ICI boilers, LNB & FGR on Catalytic Cracking, Process Heaters, & Coke Ovens, and OXY-Firing on Pressed and Container Glass Manufacturing, because reductions from those source groups are not available for $3,300 per ton or less.

At a cost level of $3,300 per ton or less, there are a number of remaining source groups with substantial reduction potential. However the table also identifies several source groups whose reduction potential is not significant, and which EPA did not weigh heavily in assessing the aggregate non-EGU NOx reduction potential. This is because the aggregate potential reductions from these "insignificant" source groups is small. These "insignificant" source groups comprise those with many small sources, as well those containing a limited number of larger sources; for either of these types of groups, potential aggregate emission reductions are small relative to reductions available from other source categories. The EPA does not believe that small sources have significant potential in the aggregate because most small sources emit less than 100 tons of NOx per year. (It is worth noting that small sources account for a significant percentage of the total number of non-EGU point sources. Please see Appendix A/B for more information on the number of sources within certain states.) The EPA therefore excludes from the focus of this analysis these insignificant source groups, namely, those with aggregate potential reductions of 1,000 tons per year or less (which represents less than 0.1 percent of the anthropogenic ozone season inventory).

The EPA will now focus on the several source groups with significant cost-effective reductions identified in Table 3. These source groups include cement kilns, two types of cement manufacturing (dry and wet), gas turbines, four separate groups of natural gas RICE, incinerators, boilers & process heaters, by-product coke manufacturing, ammonia production, and flat glass manufacturing. These remaining source groups are listed below with their control technologies, estimated control costs, and estimated installation time.

[14] $3,300 per ton represents the $2,000 per ton value (in 1990 dollars) used in the NOx SIP call, adjusted to the 2011 dollars used throughout this proposal.

These groups have been organized into 7 categories for clarity, based on either common control technologies (categories 1 through 6) or similarity of source groups (category 7).

Category 1

Cement Mfg (dry)	SNCR	$1,255	42-51 weeks
Incinerators	SNCR	$1,842	42-51 weeks
By-Product Coke Manufacturing	SNCR	$2,673	42-51 weeks

Category 2

Cement Kilns	Biosolid Injection Technology (BSI)	$410	Uncertain

Category 3

Gas Turbines	Low NOx Burner (LNB)	$800	6-8 months

Category 4

Cement Mfg (wet)	Mid-Kiln Firing	$73	5-7 months

Category 5

Boilers & Process Heaters	SCR	$2,235	28-58 weeks
Ammonia Production	SCR	$2,896	28-58 weeks

Category 6

Glass Manufacturing - Flat	OXY-Firing	$3,097	Uncertain

Category 7

Gas RICE Pipeline Compressors	Adjust AFR and Ignition Retard	$249	Uncertain
Gas RICE Miscellaneous	Adjust AFR and Ignition Retard	$447	Uncertain
Gas RICE Pipeline Compressors, Rich Burn	NSCR	$517	Uncertain
Gas RICE Pipeline Compressors, Lean/Clean Burn	Low Emission Combustion (LEC)	$649	Uncertain

The EPA makes the following observations about the potential reductions from these significant cost-effective categories.

The source groups listed in Category 1 would utilize SNCR as the recommended control technology. The time necessary to install SNCR equipment is generally well known. A typical installation timeline of 42-51 weeks is generally needed to complete an SNCR project going from the bid evaluation through startup. Based on this fact alone (which does not consider additional time likely necessary for permitting or installation of monitoring equipment), the ability for SNCR technology to be installed and operational in time for the 2017 ozone season seems very unlikely.

The source group listed in Category 2 contains a specific source of uncertainty in regards to biosolid injection technology (BSI). Due in large part to the lack of widespread use of this control technology, research performed by the EPA has been unable to uncover any reliable information on the time required to install the necessary BSI equipment on cement kilns. Compliance timing with regard to biosolid injection technology should therefore be considered extremely uncertain. Based on this fact alone (and aside from additional time likely necessary for permitting or installation of monitoring equipment), the ability for this technology to be installed and operational at all facilities in this category in time for the 2017 ozone season is unknown.

The source group listed in Category 3 would utilize LNB as the recommended control technology, with a necessary installation time of approximately 6-8 months. Some of the LNB combustion control technology identified for non-EGU sources reflects a different technology that may have different timing considerations than that considered for EGU boilers. For instance, LNB at non-EGU combustion turbines in this assessment refers to "dry low-NOx burners" (DLNB) which, in addition to the usual diffusion burner, typically also include provisions to "premix" natural gas and combustion air prior to combustion. In spite of the similarity in naming, this is a different technology than the LNB technology examined and assumed for reductions at EGU boilers. Therefore, the same timing assumptions assumed and demonstrated on the EGU side are not necessarily applicable to combustion control technology for non-EGU sources. Moreover, non-EGUs of any type – boiler or turbine – that are not currently required to monitor and report in accordance with 40 CFR Part 75 will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting (such as those EGUs covered under federal transport rulemakings and this one). Installation of NOx monitors for the reporting of NOx mass requires the construction of platforms, CEM shelters, procurement of equipment, certification testing, and electronic data reporting programming of a data handling system. These added timing considerations on the non-EGU sources make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

The source group listed in Category 4 would utilize mid-kiln firing as the recommended control technology. A fairly well-known aspect is the time necessary to install this equipment; typically, 5-7 months is needed to complete a mid-kiln firing project going from the bid evaluation through startup. However, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe proposed in this rule less likely and more uncertain for industrial sources such as those in the cement manufacturing (wet) source group.

The source groups listed in Category 5 would utilize SCR as the recommended control technology, with an installation time of 28-58 weeks for SCR (dependent on exhaust gas flow rates; larger systems require longer installation times). Based on the installation time frame alone (which does not consider additional time likely necessary for permitting or installation of monitoring equipment), the ability for SCR technology to be installed and operational in time for the 2017 ozone season seems unlikely. In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as those in Category 5 source groups.

The source group listed in Category 6 would utilize OXY-Firing as the recommended control technology, with an uncertain necessary installation. A specific source of uncertainty with regard to the estimated installation time of this control technology is that OXY-Firing is generally installed only at the time of a furnace rebuild, which rebuilds may occur at infrequent intervals of a decade or more.[15] In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as those in Category 6 source group.

Finally, the source groups listed in Category 7 are all RICE. While some of the recommended control technologies may involve installation timelines that are relatively short on a per-engine basis, there is substantial uncertainty in large-scale installation over numerous sources. References indicate that implementation of NOx controls of any type on a large number of RICE will require significant lead time to train and develop resources to implement emission reduction projects; market demand could significantly exceed the available resource base of skilled professionals.[16] Additionally, in order not to disrupt pipeline capacity, engine outages must be staggered and scheduled during periods of low system demands for those engines involved in natural gas pipelines (as is the case with 3 of the 4 RICE source groups with significant cost-effective reductions). In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as RICE.

4 Conclusion

The above preliminary analysis performed by the EPA indicates that uncertainty exists regarding whether significant aggregate NOx mitigation is achievable from non-EGU point sources by the 2017 ozone season. Reducing this uncertainty requires further understanding of potentially available control measures that could have annualized costs of $3,300 per ton or less. In addition, further implementation of the recommendations in the Appendices to this TSD would also reduce our uncertainty regarding the control measures included in future non-EGU NOx control strategy efforts.

While a number of source groups with control options were identified, the EPA did not further examine control options above $3,300 per ton, consistent with the range analyzed for EGUs in this proposal and with what the EPA has identified in previous transport rules as highly cost-effective. At a cost level of $3,300 per ton or less, a number of source groups

[15] See Appendix B.

[16] "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry," Innovative Environmental Solutions Inc., July 2014.

remained, however the EPA believes several of these source groups are not significant. Of the remaining source groups, a variety of considerations indicated the ability for control technology to be installed and operational in time for the 2017 ozone season seemed unlikely, with an overarching consideration being that non-EGUs of any type that are not currently required to monitor and report in accordance with 40 CFR Part 75 will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting. These added timing considerations on the non-EGU sources make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

With all of these factors being considered, the limited available information points to an apparent scarcity of non-EGU reductions that could be accomplished by the beginning of the 2017 ozone season. As noted in the proposed rule, this conclusion has led EPA to focus the current proposed FIPs on EGU reductions. The proposal acknowledges that this may not be the full remedy that is ultimately be needed to eliminate an upwind state's significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS (or, for that matter, the 2015 ozone NAAQS). Emissions reductions from the non-EGU categories discussed above may be necessary, though on a longer timeframe than the 2017 compliance deadline being proposed in this rulemaking. EPA intends to explore this question further in the near future and welcomes comment on any of the information in this TSD to assist with that effort.

May 2014

Update of NOx Control Measure Data in the CoST Control Measure Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines

Final Report

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Revised Draft Report

October 2014

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Appendixes

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SECTION 1
INTRODUCTION

The U.S. Environmental Protection Agency (EPA) Health and Environmental Impacts Division (HEID) has developed the Control Strategy Tool (CoST) to support national- and regional-scale multipollutant air quality modeling analyses. CoST allows users to estimate the emissions reductions and costs associated with future-year emission control strategies, and then to generate emission inventories that reflect the effects of applying the control strategies. The tool uses EPA HEID's Control Measures Database (CMDB) to develop control strategies and provides a user interface to that database. The CMDB is a relational database that contains information on an extensive set of control measures for point sources, nonpoint sources, and mobile sources. Information contained in the database includes descriptions of the measures, control efficiencies for the pollutants affected, costs of control, and the types of sources or processes to which the control measures can be applied. The database includes robust cost equations to determine engineering costs for some control measures that take into account how control costs vary with respect to variables for the source such as unit size or flow rate. The database also includes simple cost factors for all source types in terms of dollars per ton of pollutant reduced that can be used to calculate the cost of the control measure if the applicable source variable data are unavailable or no equation has been developed.

This report presents the results of an effort to review and enhance the CMDB with new and/or updated NOx control measure data for the following four industrial source categories: ammonia reformers, combustion turbines (nonEGU), glass manufacturing, and lean burn reciprocating internal combustion engines. Section 2 of this report describes the procedures used to locate more recent data than that currently in the CMDB for control measures applicable to ammonia reformers. Section 2 also identifies the source of the new data, describes any modifications to the assumptions or procedures in the referenced analyses needed to make the results consistent with results for other control measures in the database (such as operating hours for determination of total annual costs), and describes the specific recommended changes or additions to the database. Sections 3 through 5 of this report provide similar details for combustion turbines, glass manufacturing, and lean burn reciprocating internal combustion engines, respectively. Appendix A presents all of the records for ammonia reformer control measures in each of the CMDB tables showing their content after making the recommended revisions described in the report. Appendixes B through D provide comparable tables for the combustion turbine, glass manufacturing, and lean burn reciprocating internal combustion engine (RICE) source categories, respectively. Appendix E provides answers to questions on lean-burn RICE NOx emissions and available control measures. It should be noted that these revisions and updates will improve the accuracy and quality of NOx non-EGU control strategy and cost analyses for EPA rulemakings.

SECTION 2
AMMONIA REFORMERS SECTOR

The control measures database includes the following NO_X emissions control measures for ammonia reformers:

- Oxygen trim and water injection,
- Low NO_X burners and flue gas recirculation,
- Selective non-catalytic reduction (SNCR),
- Selective catalytic reduction (SCR), and
- Low NO_X burners.

In order to update the existing control measures database, a literature search was conducted using the following terms:

- reformer
- cost
- "NO_X" or "nitrogen oxide"
- "Low NO_X burner" or "LNB"
- "Flue gas recirculation" or "FGR"
- oxygen trim
- water injection
- "Selective catalytic reduction" or "SCR"
- "Selective non catalytic reduction" or "SNCR"
- emission reduction
- control efficiency

Due to the use of SCR and SNCR to control NO_X emissions and the fact that ammonia is used in the operation of SCR and SNCR, the literature search resulted in NO_X reductions on processes other than ammonia production.

In order to focus on ammonia production, a focused internet search for operating permits, BACT analyses, and NO_X controls was conducted using the 22 ammonia production facilities in the United States.

As a result of the following facts, most of the internet search results included NO_X reductions from the production of nitric acid production instead of ammonia production:

- The NO_X emissions from nitric acid production are covered by a New Source Performance Standard (NSPS) codified as Subpart G and Subpart Ga of Part 60.
- Nitric acid facilities covered by the NSPS are required to install NO_X continuous emission monitoring systems (CEMS).
- Many nitric acid facilities use SCR to control NO_X emissions.
- Many ammonia production facilities are co-located with nitric acid production facilities.

The internet search resulted in one new NO_X reduction project, which was the result of a voluntary agreement between Terra Nitrogen and the Indian Nations Council of Governments to install "ultra-low NO_X burner technology to an existing ammonia reformer [and] reduce the unit's NO_X emissions by approximately 60% at a projected capital cost of two million dollars." The existing ammonia reformer is located at Terra Nitrogen, L.P., Verdigris Plant in Claremore, Oklahoma.

Based on information known to EPA and collected for this report, Low NO_X burner technologies are known and demonstrated control techniques for ammonia reformers.

The following sections outline the deletions, additions, changes, and other comments recommended for the CMDB in relation to NO_X emissions from ammonia reformers.

2.1 Recommended Deletions

No deletions are recommended.

2.2 Recommended Additions

The only addition to the CMDB is to add the following reference: *Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O_3 Flex Program*. Prepared by Indian Nations Council of Governments (INCOG), 201 W. 5th Street, Suite 600, Tulsa, OK 74103. March 6, 2008. http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf.

This addition is shown in Appendix A as Table A-1.

2.3 Recommended Changes

Updates to costs and Efficiencies.

Changes to one record (LNB applied to large source types) are recommended to reflect the new reference dated March 6, 2008.

Using the new reference and a reference already contained in the CMDB, the following assumptions were made:

- NO_X reductions of 425 tons per year[1]
- Capital cost of $2 million[1]
- Maintenance costs are 2.75% of capital costs[2]
- Equipment life of 10 years
- Interest rate of 7%
- Capital recovery factor of 0.1424.

The resulting annual costs are $339,800 and the cost effectiveness is $800 per ton of NO_X reduction (both in 2008 dollars). The capital to annual cost ratio is 5.9.

The previous entry showed a cost effectiveness of $650 per ton of NO_X reduction (in 1990 dollars) and a capital to annual cost ratio is 5.5. The changes are included in Appendix A as Table A-2 and Table A-3. Changes are indicated by red, italic text.

Updates to Source Classification Codes.

The U.S. Environmental Protection Agency (USEPA) developed the Source Classification Code (SCC) system, which assigns an eight digit code to each emission unit based on the general criteria pollutant emission point type, the major industry group, specific industry group, and specific process unit/fuel combination. The system allows similar emission points to be grouped together for analyses.

For ammonia reformers, there are seven applicable SCCs, as shown in Table 2-1.

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[1] Indian Nations Council of Governments (INCOG), 2008: Indian Nations Council of Governments (INCOG), "Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O3 Flex Program," March 6, 2008. Downloaded from http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf.

[2] U.S. Environmental Protection Agency. Alternative Control Techniques Document— NO_X Emissions from Process Heaters (Revised), document EPA-453/R-93-034, dated September 1993.

Table 2-1. Applicable SCCs for the Ammonia Production Industry

SCC	SCC 1	SCC3	SCC6	SCC8
30100305	Industrial Processes	Chemical Manufacturing	Ammonia Production	Feedstock Desulfurization
30100306	Industrial Processes	Chemical Manufacturing	Ammonia Production	Primary Reformer: Natural Gas Fired
30100307	Industrial Processes	Chemical Manufacturing	Ammonia Production	Primary Reformer: Oil Fired
30100308	Industrial Processes	Chemical Manufacturing	Ammonia Production	Carbon Dioxide Regenerator
30100309	Industrial Processes	Chemical Manufacturing	Ammonia Production	Condensate Stripper
30100310	Industrial Processes	Chemical Manufacturing	Ammonia Production	Storage and Loading Tanks
30100399	Industrial Processes	Chemical Manufacturing	Ammonia Production	Other Not Classified

In an analysis of NO_X emissions for the Ozone Transport Region in 2011, four of the SCCs in Table 2-1 were identified. These SCCs are 30100306, 30100307, 30100310, and 30100399. Only SCCs 30100306 and 30100307 are associated with ammonia reformer NO_X controls in the current CMDB.

The known control techniques for ammonia reformers are typically used for point emission sources, such as stacks. Emissions from SCC 30100310 are not typically vented, so capture and control of these emissions is likely not feasible. Therefore, no changes related to SCC 30100310 are recommended for the CMDB.

For the purposes of this analysis, SCC 30100399 is assumed to include combustion emissions from gaseous fuels other than natural gas. Therefore, all control techniques that are applicable to natural gas fired ammonia reformers are assumed to also apply to SCC 30100399. Also, the cost to control NO_X emissions from gaseous fuels is assumed to be comparable to the cost to control NO_X emissions from natural gas. Therefore, the costs related to those control techniques are assumed to apply to SCC 30100399.

The applicable SCC from Table 2-1 was added to the Description field for each control technique in Table A-2 of Appendix A. SCC 30100306 was already included in the table; SCCs 30100305, 30100307, and 30100399 were added, where appropriate. Changes are indicated by red text.

2.4 Other Comments

Control measures used by ICI boilers. Review of NO_X control measures used for boilers was not included in this analysis. However, many of the SCR costs in the CMDB for natural gas fired ammonia reformers are based on SCR costs for Industrial/Commercial/Institutional (ICI) Boilers using Process Gas. No SCR costs specific to ammonia reformers were noted in the CMDB.

At a later time, it may be pertinent to review recent final ICI Boilers regulations or other sources for potential updates to the cost of SCR on ammonia reformers. The final major source NESHAP for ICI Boilers was promulgated on January 31, 2013 and the final area source NESHAP for ICI Boilers was promulgated on February 1, 2013.

Potential NO_X limits for ammonia reformers based on boiler NO_X limits. According to NO_X Reasonably Acceptable Control Technology (RACT), the states of New Jersey and New York have established emission limits for ICI Natural Gas Boilers (greater than 100 million BTU per hour) that could be applicable to natural gas ammonia reformers. These RACT limits are shown in Table 2-2.

Table 2-2. RACT NO_X Limits for ICI Natural Gas Boilers

State	Boiler Size	Limit (lb NO_X/MMBTU)	Effective Date
New Jersey[a]	>100 MMBTU	0.10	Already in effect
New York	>100 MMBTU and ≤ 250 MMBTU	0.06	7/1/14
New York	> 250 MMBTU	0.08	7/1/14

[a] The limit also applies to other indirect heat exchangers.

SECTION 3
COMBUSTION TURBINES

The CMDB includes the following NO_X emissions control measures for Combustion Turbines:

- Water injection for natural gas-fired turbines (achieves 76 percent reduction)
- Steam injection for natural gas-fired turbines (achieves 80 percent reduction)
- Low NOx Burners for natural gas-fired turbines (achieves 84 percent reduction)
- SCR on natural gas-fired turbines that also have water injection (achieves 95 percent reduction)
- SCR on natural gas-fired turbines that also have steam injection (achieves 95 percent control)
- SCR on natural gas-fired turbines that also have low NOx burners (achieves 94 percent reduction)
- Water injection for oil-fired turbines (achieves 68 percent reduction)
- SCR on oil-fired turbines that also have water injection (achieves 90 percent reduction)
- Water injection for jet fuel-fired turbines (achieves 68 percent reduction)
- SCR on jet fuel-fired turbines that also have water injection (achieves 90 percent reduction)
- Water injection for aeroderivative turbines (achieves 40 percent reduction)

All of the cost data are in 1990 dollars, except the costs of water injection for aeroderivative turbines, which are in 2005 dollars. In addition, all of the costs are based on estimated operation for 8,000 hr/yr, except the costs of water injection for aeroderivative turbines, which are for intermittently operated units. The costs in 1990 dollars are based primarily on analyses in EPA's 1993 ACT document for NOx Emissions from Stationary Gas Turbines (EPA, 1993). Capital and annual cost equations are provided for all of the controls except those for jet fuel-fired turbines and water injection for aeroderivative turbines.

<u>Literature search</u>. In order to update the existing CMDB, a literature search was conducted for articles and papers published since 2008. In addition, an internet search was conducted for BACT analysis reports and control technology reports prepared for federal and

state agencies and RPOs. The literature search did not identify any documents with cost data, but the internet search identified the documents listed in Section 3.5 of this report.

Changes to CMDB. The following sections outline the deletions, additions, and other changes recommended for the CMDB in relation to NO_X emissions from Combustion Turbines. All cost data and calculations are in an Excel Worksheet (RTI, 2014). Copies of the CMDB tables with recommended revisions to the records for combustion turbine controls are provided in Appendix B.

The coefficient of determination (R^2) is 1.0 for many of the regression equations presented in sections 3.2 and 3.3. The R2 value is exactly 1.0 in cases where the analysis was based on only two data points; these cases are noted in the discussions for the particular control measure. In other cases, actual R2 values greater than 0.995 have been rounded to 1.0. These high values likely are due to the fact that available data for most control measures are from a single source, and those sources may have already developed a correlation and then picked specific data points from that correlation for presentation in their documentation.

3.1 Recommended Deletions

RTI recommends deleting the record for water injection for aeroderivative turbines because the estimated costs are for combustion turbines that operate on a limited and intermittent basis (i.e., peaking EGUs). In principle, data for small EGU combustion turbines would be acceptable for estimating costs of control measures for nonEGUs. However, the limited operation of peaking units is inconsistent with the assumed operating time of about 8,000 hr/yr for all of the other nonEGU combustion turbine control measures in the database. For several SCCs that are currently associated with this control measure in the CMDB we are recommending applying other existing control measures, as discussed in Section 3.3.11 of this report.

The CMDB also currently applies several gas turbine control measures to reciprocating internal combustion engine SCCs and to gas turbine SCCs for evaporative losses from fuel storage and delivery systems. We recommend deleting these applications of the gas turbine control measures, as discussed in Section 3.3.11 and Section 5.9 of this report.

3.2 Recommended Additions

There are 3 control technique additions for emerging technologies to be added to the CMDB; these additions include:

- Catalytic Combustion; Gas Turbines—Natural Gas;

- EMx and Water Injection; Gas Turbines—Natural Gas;
- EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas.

3.2.1 Catalytic Combustion; Gas Turbines—Natural Gas (NCATCGTNG)

Catalytic combustion is a flameless process that allows fuel oxidation to occur at temperatures approximately 1800°F lower than those of conventional combustors (OSEC, 1999). Lower temperatures are desirable because NOx emissions levels are strongly correlated with temperature. One design that has been commercialized is the Xonon™ combustor (now called K-Lean™). In the Xonon combustor, a small amount of fuel is burned in a low temperature pre-combustor. Additional fuel is then mixed with the air and combustion gases from the pre-combustor and passed through a catalyst module. The catalyst promotes a flameless reaction between some of the fuel and oxygen. The gases then enter a burnout zone in which the remaining fuel burns. The maximum temperature in the system is between 2300°F and 2700°F. In addition to low NOx emissions, the catalytic combustor generates very little CO emissions. (Peltier, 2003; CARB, 2004; Leposky, 2004; Kawasaki, 2010; Quackenbush, 2012)

Since 1999 at least six Xonon combustors have been installed; all are 1.4 MW units (CARB, 2004; Kawasaki, 2010; Quackenbush, 2012). Testing of four of the operating Xonon combustors has shown NOx emissions less than 3 parts per million by volume on a dry basis (ppmvd) at 15% oxygen, and permit limits range from 3 ppmvd to 20 ppmvd at 15% oxygen (CARB, 2004; Quackenbush, 2012). Several companies have conducted research into developing larger catalytic combustors and other types of designs, but no information was found indicating that such units have been commercialized (CARB, 2004; Leposky, 2004; Cybulski, 2006).

Although one type of catalytic combustor has been commercialized, we recommend considering catalytic combustion as an emerging technology in the CMDB because so few units are in operation, and they are all only one size. In addition, as of 1999, issues with catalytic combustors include the need for the air-fuel mixture to have completely uniform temperature, composition, and velocity profile to assure effective use of all the catalyst and to prevent damage to the substrate from high temperatures. Also the catalyst durability is uncertain (OSEC, 1999).

The recommended costs are based on costs presented in a report by Onsite Sycom Energy Corporation (OSEC, 1999). The only change we made to the OSEC costs was to calculate capital recovery using an interest rate of 7 percent instead of 10 percent; this change makes the capital recovery costs consistent with guidance in Circular A-4 from the Office of Management and Budget. Table 3-1 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the catalytic combustion NOx control technology. With an outlet concentration of 3 ppmvd, catalytic combustion achieves an average reduction of 98 percent relative to uncontrolled conventional diffusion combustion.

Table 3-1. Summary of Cost Effectiveness and Supporting Data for Catalytic Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
		Avg. ppmvd	tpy			
Small (5.2)	1999	150	<365	3	920	1.7
Small (26.3)	1999	130	>365	3	670	1.2
Large (170)	1999	210	>365	3	370	0.7

Based on regression of the data in the analysis, the best fit trend lines are represented by the following equations for the uncontrolled scenario:

$$\text{Total capital investment (1999 dollars)} = 20668 \times (\text{MMBtu/hr})^{\wedge\,0.57} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 4254.2 \times (\text{MMBtu/hr})^{\wedge\,0.82} \quad (R^2=1.0)$$

For all but the smallest turbines, the incremental cost of catalytic combustors relative to conventional combustors is less than the incremental cost of DLN combustion versus conventional combustors. Thus, there are no incremental capital costs for catalytic combustion relative to conventional combustion. However, there are incremental annual costs because the cost of catalyst replacement is high. A best fit equation for incremental catalytic combustion total annual costs relative to a RACT baseline of DLN combustion is:

$$\text{Total annual cost (1999 dollars)} = 743.22 \times (\text{MMBtu/hr}) + 54105 \quad (R^2=1.0)$$

3.2.2 EMx and Water Injection; Gas Turbines—Natural Gas (NEMXWGTNG)

Like SCR, EMx™ (formerly called SCONOX™) is a post-combustion catalytic NOx reduction technology. EMx uses a precious metal catalyst and a NOx absorption/regeneration process to convert CO and NOx to CO2, H2O, and N2. NOx reacts with the potassium carbonate absorbent coating the surface of the oxidation catalyst in the EMx reactor, forming potassium nitrites and nitrates that are deposited onto the catalyst surface. Each segment, or "can," within the reactor becomes saturated with potassium nitrites and nitrates over time and must be desorbed. Regeneration is accomplished by isolating the can via stainless steel lovers and injecting hydrogen diluted with steam. Hydrogen is generated onsite with a small reformer that uses natural gas and steam as input streams. The hydrogen concentration of the reformed gas is typically 5 percent. Hydrogen and carbon dioxide react with the potassium nitrites and nitrates to form N2 and H2O and to regenerate the potassium carbonate for another absorption cycle. (OSEC, 1999; CARB, 2004)

At least 8 EMx systems at 6 facilities have been installed on combustion turbines with capacities up to 45 MW. Permit limits at most of these facilities have been set at 2.5 ppmvd for gas-fired operation. EPA has certified it as "demonstrated in practice" LAER-level technology that reduces NOx to less than 5 ppmvd. The operating range of the catalyst is 300 to 700°F, which means the technology is not applicable for simple cycle turbines. The vendor for the technology has indicated that these systems also reduce carbon monoxide emissions to undetectable levels (essentially 100 percent reduction), reduce volatile organic compound emissions by greater than 90 percent, and reduce fine particulate matter emissions by 30 percent (EmeraChem, 2004). Test data documenting these reductions are not available. For the purposes of the CMDB database, we recommend that this control measure be listed as an emerging technology (rather than known) because its use has been limited to only a few small turbines.

The recommended costs for EMx in the combined EMx/water injection control measure are based on costs presented in a 2008 cost estimate prepared by EmeraChem Power for the Bay Area Air Quality Management District (ECP, 2008). For the purposes of developing 2008 cost inputs for the CMDB, we made the following changes to the data and assumptions used in the ECP analysis:

- Increased the indirect cost for engineering from $200,000 to $255,000 for the 50 MW turbine. ECP's documentation indicated that this cost (as well as most of the other direct installation and indirect costs) would be the same as for an SCR system on the same turbine. The reported cost of $200,000 was inconsistent with this statement.

- Increased the contingencies cost for the 50 MW turbine from $76,486 to $244,101. This change makes the cost consistent with ECP's statement that the cost for contingencies is estimated to be equal to 5 percent of the total purchased equipment cost, excluding the cost of the precious metals in the catalyst, sales taxes, and freight.

- Added a cost for the performance loss due to back pressure from the EMx system for both turbines. ECP estimated the loss to be 0.5 percent, which is consistent with the estimate in the 1993 ACT for SCR and the estimate OSEC used in a cost analysis for SCONOx (EPA, 1993; OSEC, 1999). However, the ECP analysis did not include a corresponding dollar amount for this element.

- Changed the operating hours from 7,884 hr/yr to 8,000 hr/yr. This change also had a small effect on the annual costs for utilities.

- Added costs for natural gas to generate steam for the 50 MW turbine using the same procedures presented in the ECP analysis for the 180 MW turbine. ECP did not report the basis for the amount of steam needed for the 180 MW turbine. Therefore, we plotted the reported steam consumption versus turbine size for this unit and for two turbines identified in a CARB analysis (CARB, 2004). We calculated the quantity of steam needed for EMx on the 50 MW turbine using the regression equation from this plot. Note that the unit cost for natural gas is $9.75/1000 scf. This was a reasonable annual average cost in 2008, but it would be much too high for an analysis in 2014.

- Deleted the credit for recovery of precious metals in the spent catalyst because the cost for replacement catalyst considers only the difference between the total purchase price minus the value of the recovered material.

- Estimated the annualized cost of replacement catalyst (both the non-precious metal substrate and the precious metal coating) using the future worth factor, whereas the cost in the ECP analysis was the purchased cost divided by the 10-year replacement interval.

- Estimated the cost of annual catalyst cleaning based on the average if data reported by CARB (CARB, 2004) plus the amounts reported by ECP. Although ECP reported a slightly higher cleaning cost for the 180 MW turbine than for the 50 MW turbine, an analysis of all the cleaning data showed no correlation with turbine size. Thus, we used the average of all reported costs for both turbines.

- Revised the indirect annual cost for administrative charges. ECP estimated that these costs are the same as for an SCR system on the same turbines. We factored the cost as 2 percent of the TCI for the applicable EMx systems, which is consistent with the approach for all control devices in the EPA Control Cost Manual. This resulted in slightly higher costs.

- Increased the indirect costs for insurance, property tax, and capital recovery for both turbines because the ECP analysis excluded the precious metal costs from the TCI used in these calculations.

- Calculated capital recovery using an interest rate of 7 percent instead of 10 percent.

The capital costs for water injection in the combined EMx/water injection control measure were estimated in 1999 dollars using the regression equation for the water injection control measure (see Section 3.3.1) and then scaled to 2008 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Total annual costs for water injection were first estimated in 1999 dollars using the regression equation for the water injection control option. On average, 25 percent of these costs were estimated to be for indirect costs that are factored from the system capital cost, and the remaining 75 percent is for direct annual costs and overhead. To estimate the total annual costs for water injection in 2008, the indirect costs were scaled from the 1999 estimate using the CEPCI, and the direct annual costs and overhead were assumed to be the same as in 1999.

Table 3-2 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the EMx plus water injection NOx control measure. With an outlet concentration of 2 ppmvd, this control measure achieves an average reduction of 99 percent relative to uncontrolled conventional diffusion combustion.

Table 3-2. Summary of Cost Effectiveness and Supporting Data for EMx Plus Water Injection

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions: Avg ppmvd	Uncontrolled NOx Emissions: tpy	EMx Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, \$/ton NOx
Large (50-180)	2008	160[a]	>365	2.0	2,760	3.1	6,810

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in the analysis, the best fit trend lines are represented by the following power equations for the uncontrolled scenario (the R^2 =1.0 for both equations because there were only two data points in the analysis):

$$\text{Total capital investment (2008 dollars)} = 196928 \times (\text{MMBtu/hr})^{0.68}$$

$$\text{Total annual cost (2008 dollars)} = 18747 \times (\text{MMBtu/hr})^{0.86}$$

Best fit equations for incremental EMx costs relative to a RACT baseline of water injection are:

$$\text{Total capital investment (2008 dollars)} = 156349 \times (\text{MMBtu/hr})^{0.68}$$

$$\text{Total annual cost (2008 dollars)} = 17252 \times (\text{MMBtu/hr})^{0.80}$$

3.2.3 EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas (NEMXDGTNG)

Table 3-3 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the EMx plus dry low NOx combustion control measure. With an outlet concentration of 2 ppmvd, this control measure achieves an average reduction of 99 percent relative to uncontrolled conventional diffusion combustion. For the same reasons noted in Section 3.2.2, we recommend that this control measure be listed as an emerging technology in the CMDB.

Table 3-3. Summary of Cost Effectiveness and Supporting Data for EMx Plus Dry Low NOx Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		EMx Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of DLN, $/ton NOx
		Avg ppmvd	tpy				
Small (4.2)	1999	134	<365	2.0	2,860	3.9	14,940
Small (23)	1999	174	>365	2.0	1,720	4.1	10,270
Large (170)	1999	210	>365	2.0	840	3.9	6,600
Large (50-180)	2008	160[a]	>365	2.0	2,050	4.1	12,390

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

The recommended costs for EMx in 2008 dollars for the combined EMx/dry low NOx combustion control measure are the same as in the estimate for the EMx/water injection control measure described in Section 3.2.2. The recommended costs for EMx in 1999 dollars are based on an analysis prepared by Onsite Sycom Energy Corporation (OSEC, 1999). For this analysis the only changes we made to OSEC's analysis were to reduce the operating hours from 8,400 hr/yr to 8,000 hr/yr, which slightly reduced the energy penalty and utilities costs, and we calculated the capital recovery factor using an interest rate of 7 percent instead of 10 percent. Note that the total annual costs for natural gas (or purchased steam) are considerably lower in this analysis than in the 2008 analysis because the unit cost of natural gas was considerably lower in 1999.

The recommended total capital investment and total annual cost for dry low NOx combustion in 1999 dollars for the combined EMx/dry low NOx combustion control measure are the same as in the estimate for the dry low NOx combustion control measure alone as described in Section 3.3.3. The recommended total capital investment for dry low NOx combustion in 2008 dollars was estimated in 1999 dollars using the regression equation for the water injection control measure (see Section 3.3.1) and then scaled to 2008 dollars using the CEPCI. The recommended total annual costs for dry low NOx combustion consist of capital recovery plus the cost for parts and repair; capital recovery costs in 2008 dollars were estimated by escalating the 1999 costs using the CEPCI, and annual parts and repairs costs were assumed to be the same in 2008 as in 1999.

Based on regression of the data in both the 1999 and 2008 cost analyses, the best fit trend lines are represented by the following power equations for the uncontrolled scenario (the R^2 =1.0 for the equations in 2008 dollars because there were only two data points in the analysis; R^2 for the equations in 1999 dollars round to 1.0 when only two significant figures are presented):

$$\text{Total capital investment (1999 dollars)} = 58237 \times (\text{MMBtu/hr})^{0.78}$$

$$\text{Total annual cost (1999 dollars)} = 15004 \times (\text{MMBtu/hr})^{0.78}$$

$$\text{Total capital investment (2008 dollars)} = 126892 \times (\text{MMBtu/hr})^{0.74}$$

$$\text{Total annual cost (2008 dollars)} = 20041 \times (\text{MMBtu/hr})^{0.80}$$

Best fit equations for incremental EMx costs relative to a RACT baseline of DLN combustion are:

$$\text{Total capital investment (1999 dollars)} = 65163 \times (\text{MMBtu/hr})^{0.72}$$

$$\text{Total annual cost (1999 dollars)} = 13702 \times (\text{MMBtu/hr})^{0.76}$$

$$\text{Total capital investment (2008 dollars)} = 156349 \times (\text{MMBtu/hr})^{0.68}$$

$$\text{Total annual cost (2008 dollars)} = 17252 \times (\text{MMBtu/hr})^{0.80}$$

3.3 Recommended Changes

This section presents updated cost estimates for combustion turbine control measures that are currently in the CMDB, and it describes the basis for such changes. These changes include both more recent costs for some control measures as well as minor revisions to existing estimates for other control measures. The changes affect both cost per ton values and equations.

This section also identifies applicable SCCs for the new control measures described in Section 3.2, and it identifies additional SCCs for which the control measures in this section are applicable.

3.3.1 Water Injection; Gas Turbines—Natural Gas (NWTINGTNG)

Recommended updates to the costs for water injection are based on analyses in a report prepared by OnSite Sycom Energy Corporation for the U.S. Department of Energy (OSEC, 1999). OSEC estimated costs for some of the same small turbine model sizes as in EPA's 1993 ACT document (4 MW and 23 MW). OSEC obtained water injection equipment costs in 1999 dollars. They then estimated total capital investment and total annual costs using the same procedures as in the 1993 ACT document, and they concluded that 1999 costs for water injection were essentially the same as the 1990 costs presented in the ACT document. Because the ACT analysis included a greater number of models over a wider range of sizes, RTI recommends continuing to use the cost data from the ACT analysis in the CMDB, except the cost year should be updated from 1990 to 1999. RTI also recommends the four additional changes noted below.

Our second recommendation is to split the record for small sources into two records—one for sources with uncontrolled emissions less than 365 tpy, and the other for emissions greater than 365 tpy. The 2006 AirControlNET Documentation Report indicates that small sources are turbines with design outputs up to 34.4 MW. Four model turbines in the ACT analysis have outputs below this threshold. The two turbines with uncontrolled emissions <365 tpy have an average cost effectiveness of $1,790/ton of NOx. The two turbines with uncontrolled emissions >365 tpy have an average cost effectiveness of $1,000/ton of NOx.

Our third recommendation is to revise the control efficiency for water injection from 76 percent to 72 percent. The 76 percent control level is the average reduction for all 6 model turbines in the 1993 ACT analysis. Five of those models were guaranteed to reduce NOx emissions to less than 42 ppmvd, while the sixth was guaranteed to meet 25 ppmvd. Although water injection may be more effective on some combustion turbines than others, 42 ppmvd is the generally accepted threshold. Thus, we think this threshold should be incorporated in the CMDB. The average reduction of the 5 models in the 1993 ACT analysis with an outlet concentration of 42 ppmvd was 72 percent.

Our fourth recommendation is to use a capital to annual cost ratio of 2.4 in the new record for small sources with uncontrolled emissions >365 tpy; this is the average value for the two turbines in the ACT analysis in this size range. (The capital to annual cost ratio for the small sources with uncontrolled emissions <365 tpy would remain at 3.1 because this is the average value for the two turbines in this size range; it is not clear why this value was applied for all small sources in the current version of the CMDB.) The total annual costs in this calculation are based on using a 7 percent interest rate in the calculation of capital recovery, instead of the 10 percent value in the 1993 ACT. Even if capital recovery was estimated using the 10 percent interest rate, it is not clear how the 3.1 value was developed.

Our fifth recommendation is to revise the constants in the CMDB table of equations for estimating capital and annual costs. Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for both uncontrolled and RACT baseline scenarios:

$$\text{Total capital investment (1999 dollars)} = 27665 \text{ x (MMBtu/hr)} \wedge {}^{0.69} \ (R^2 = 0.97)$$

$$\text{Total annual cost (1999 dollars)} = 3700.2 \text{ x (MMBtu/hr)} \wedge {}^{0.95} \ (R^2 = 0.95)$$

3.3.2 Steam Injection; Gas Turbines—Natural Gas (NSTINGTNG)

The only available information on the cost of steam injection was in the 1999 report from Onsite Sycom Energy Corporation (OSEC, 1999). OSEC discussed steam injection only in the context of large GE Frame 7F turbines (170 MW). They noted that only the first such model, operational in 1990 when the ACT analysis was being conducted, was equipped with steam injection. All subsequent units (at least through 1999) were equipped with DLN combustion technology.

Because the limited available information suggests that steam injection costs, like water injection costs, were essentially the same in 1999 as in 1990, we recommend continuing to base the steam injection costs on the results in the 1993 ACT, but update the cost year from 1990 to 1999. In addition, as for water injection, we recommend splitting the one record for small sources into two records—one for sources with uncontrolled NOx emissions <365 tpy, and the other for uncontrolled NOx emissions >365 tpy. This split results in average cost effectiveness values of $1,690/ton of NOx for the small sources with uncontrolled NOx emissions <365 tons/yr and $820/ton of NOx for the small sources with uncontrolled NOx emissions >365 tons/yr. The capital cost to annual cost ratios also are slightly less than the current values in the CMDB.

Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for both uncontrolled and RACT baseline scenarios:

$$\text{Total capital investment (1999 dollars)} = 43092 \times (\text{MMBtu/hr}) \wedge {}^{0.82} \; (R^2=0.95)$$

$$\text{Total annual cost (1999 dollars)} = 7282 \times (\text{MMBtu/hr}) \wedge {}^{0.76} \; (R^2=0.96)$$

3.3.3 Dry Low NOx Combustion; Gas Turbines—Natural Gas (NDLNCGTNG)

Dry low NOx (DLN) combustion technology premixes air and a lean fuel mixture that significantly reduces peak flame temperature and thermal NOx formation. In some cases, this can be accomplished by using low NOx burners, but in other cases, the combustor design itself differs as well as the burner design. For example, the DLN combustor volume is typically twice that of a conventional combustor (OSEC, 1999). Therefore, we recommend revising the current control technology name in the CMDB from "Low NOx Burners" to "Dry Low NOx Combustion." In addition, the CM abbreviation should be changed from NLNBUGTNG to NDLNCGTNG.

Recommended updates to the costs for DLN Combustion are based on analyses in a report prepared by Onsite Sycom Energy Corporation for the U.S. Department of Energy (OSEC, 1999). OSEC estimated costs for some of the six turbines with design outputs ranging from 4 MW to 169 MW.

OSEC obtained installed equipment costs and annual repair costs in 1999 dollars from three turbine manufacturers, but there are some uncertainties in the data. Although the reported tabular summary indicates the equipment costs are incremental relative to the cost of a conventional combustor, the text of the report states that the costs for 169 MW turbines are the total cost to replace a conventional combustor (which may explain why the regression equation for the capital costs is linear rather than a power function). Annual costs for parts and repair for some of the turbines were proprietary for two of the small turbines and thus could not be reported. As a result, the annual costs for those turbines are biased low. In addition, because parts and repair costs were unavailable for the 169 MW turbine, OSEC assumed these costs could be represented by the costs for the 23 MW turbine.

The only change we made to the assumptions and data reported by OSEC was to calculate capital recovery using an interest rate of 7 percent instead of 10 percent.

Table 3-4 summarizes the recommended new cost effectiveness and capital to annual cost ratios for implementing the DLN combustion NOx control technology. In addition to changing these costs in the CMDB, we also recommend changing the control efficiency for DLN combustion applied to small sources from 68 percent to 84 percent. The 84 percent level is currently used for large sources, and it is consistent with the efficiency for DLN combustion (or low NOx burners) in the 1993 ACT. It appears the 68 percent entry was a data transcription error because that is the control efficiency for water injection applied to oil-fired turbines.

Table 3-4. Summary of Cost Effectiveness and Supporting Data for DLN Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		Outlet Concentration, ppmvd	Cost Effectiveness, \$/ton NOx	Capital to Annual Cost Ratio
		Avg. ppmvd	tpy			
Small (4-23)	1999	152	<365	25	300	5.0
Large (170)	1999	210	>365	25	130	7.4

Based on regression of the data in both analyses, the best fit trend lines are represented by the following revised equations for both uncontrolled and RACT baseline scenarios:

$$\text{Total capital investment (1999 dollars)} = 2860.6 \times (\text{MMBtu/hr}) + 25427 \; (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 584.5 \times (\text{MMBtu/hr})^{0.96} \; (R^2=0.95)$$

3.3.4 SCR and Water Injection; Gas Turbines—Natural Gas (NSCRWGTNG)

Recommended updates to the costs for SCR combined with water injection are based on two sets of cost analyses. One set of costs is in 1999 dollars for three turbines ranging in size from 4.2 MW to 161 MW (OSEC, 1999). The second is in 2008 dollars for two larger turbines with design outputs of 50 MW and 180 MW (ECP, 2008). For SCR, the referenced analyses estimated direct installation costs and indirect costs based on scaling from the purchased equipment costs using standard factors as in the Control Cost Manual. Annual costs were estimated for the same cost elements that were used in the SCR analysis in the 1993 ACT. Water injection costs for the two smallest turbines in the 1999 analysis were estimated as described above for the water injection control option. Water injection costs for the large turbines were not estimated in the referenced analyses.

For the purposes of developing 1999 cost inputs for the CMDB, we made the following changes to the data and assumptions used in the OSEC analysis:

- Increased the engineering cost for SCR for the 161 MW turbine from \$100,000 to \$228,865. The revised value is equal to 10 percent of the purchased equipment cost, which is consistent with the approach used for the smaller turbines. The report did not explain why \$100,000 was used instead of the factor.

- Estimated performance penalty costs and electricity costs for the blower and pumps in the ammonia injection system using operating hours of 8,000 hr/yr instead of 8,400 hr/yr.

- Calculated capital recovery for the SCR system using an interest rate of 7 percent instead of 10 percent.

- Calculated annual catalyst replacement and disposal costs using a future worth factor instead of a capital recovery factor.

- Estimated total capital investment and total annual costs for the 161 MW turbine using the regression equations for the water injection control option. (Maybe it would be better to drop the large model from this analysis and just present 1999 costs for small turbines and 2008 costs for large turbines.)

For the purposes of developing 2008 cost inputs for the CMDB, we started with the ECP analysis for SCR costs and then made the following changes to the data and assumptions:

- Calculated the performance penalty for SCR using an electricity cost of $0.06/kwh instead of $0.1/kwh and 8,000 hr/yr instead of 8,400 hr/yr. In addition, although it appears that the referenced analysis assumed a performance loss equal to 0.5 percent of the turbine's design output, the cited cost was significantly greater than it should be for that percentage loss, even if the cited electricity cost and operating hours were used in the calculation. We changed the cost to be consistent with the calculated amount.

- Calculated capital recovery for the SCR system using an interest rate of 7 percent instead of 10 percent.

- Estimated capital costs for water injection in 1999 dollars using the regression equation for the water injection control option, and then scaled the costs to 2008 dollars using the CEPCI.

- Estimated total annual costs for water injection following the same procedure described in Section 3.2.2 for the water injection portion of a combined water injection and EMx control measure. Thus, the total annual costs for water injection are the same in both control measures.

Table 3-5 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus water injection on natural gas-fired combustion turbines. Table 3-5 also presents revised incremental costs of SCR relative to a RACT baseline of water injection for the different categories of turbines. Note that the SCR outlet NOx level was assumed to be 2.5 ppmvd in the ECP analysis, which results in an overall control efficiency of 98 percent versus the 94 percent for the OSEC and ACT analyses.

Table 3-5. Summary of Cost Effectiveness and Supporting Data for SCR Plus Water Injection

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, $/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	134	<365	9	2,790	3.0	5,840
Small (22.7)	1999	174	>365	9	1,370	2.9	3,130
Large (161)	1999	210	>365	9	1,070	1.5	1,690
Large (50-180)	2008	160[a]	>365	2.5	1,830	2.7	3,170

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in both analyses, the revised best fit trend lines are represented by the following power equations for both uncontrolled scenarios (R^2=1 for the 2008 costs because the analysis was based on only two data points):

$$\text{Total capital investment (1999 dollars)} = 62962 \times (\text{MMBtu/hr})^{0.66} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 8590 \times (\text{MMBtu/hr})^{0.87} \quad (R^2=0.99)$$

$$\text{Total capital investment (2008 dollars)} = 34533 \times (\text{MMBtu/hr})^{0.85} \quad (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 6794 \times (\text{MMBtu/hr})^{0.94} \quad (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of water injection are (R^2=1 for the 2008 costs because the analysis was based on only two data points):

$$\text{Total capital investment (1999 dollars)} = 37193 \times (\text{MMBtu/hr})^{0.63} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 12065 \times (\text{MMBtu/hr})^{0.64} \quad (R^2=1.0)$$

$$\text{Total capital investment (2008 dollars)} = 10323 \times (\text{MMBtu/hr})^{0.96} \quad (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 3106.1 \times (\text{MMBtu/hr})^{0.94} \quad (R^2=1.0)$$

3.3.5 SCR and Steam Injection; Gas Turbines—Natural Gas (NSCTSGTNG)

Combined costs for SCR and steam injection were not presented in any available references. Thus, costs for combined control systems were estimated in 1999 dollars for four model turbines ranging from 4 MW to 161 MW using the procedures described above for steam injection alone and for SCR as part of combined SCR and water injection control systems. Specifically, steam injection costs for each model turbine were assumed to be the same as in the 1993 ACT, consistent with the description above for steam injection control costs. Since OSEC did not estimate SCR costs for the specific turbines in this analysis, we estimated the SCR costs using the trendlines that we developed for incremental SCR costs relative to a RACT baseline of water injection. We then summed the separate SCR and steam injection costs to obtain the combined system costs.

We also estimated costs for a combined steam injection and SCR control measure in 2008 dollars. The SCR portion of the costs are the same as for SCR in the combined water injection plus SCR control measure, as described in Section 3.3.4. Total capital investment for the steam injection portion were estimated in 1999 dollars using the regression equation developed for steam injection alone, as described in Section 3.3.2. These costs were escalated to 2008 costs using the CEPCI. Total annual costs for steam injection were first estimated in 1999 dollars using the regression equation for the steam injection control option (see Section 3.3.2). On average, 40 percent of these costs were estimated to be for indirect costs that are factored from the system capital cost, and the remaining 60 percent is for direct annual costs and overhead. To estimate the total annual costs for steam injection in 2008, the indirect costs were scaled from the 1999 estimate using the CEPCI, and the direct annual costs and overhead were assumed to be the same as in 1999.

Table 3-6 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus steam injection on natural gas-fired combustion turbines. Table 3-6 also presents revised incremental costs of SCR relative to a RACT baseline of steam injection for the different categories of turbines. Note that the incremental costs are slightly different from the costs in Table 3-5. The costs should be the same for a given turbine category. They differ because the two analyses examined a different number of turbines, and the sizes were not exactly the same. At a later date, the analysis could be improved by combining the SCR costs from both analyses and developing a single set of incremental SCR costs.

Table 3-6. Summary of Cost Effectiveness and Supporting Data for SCR Plus Steam Injection (SI)

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of SI, $/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	155	<365	9	2,570	3.3	5,550
Small (26.8)	1999	142	>365	9	1,380	3.1	2,870
Large (83–161)	1999	300	>365	9	570	2.7	1,810
Large (50–180)	2008	160[a]	>365	2.5	1,420	3.9	3,170

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in the analysis, the revised best fit trend lines are represented by the following power equations for the uncontrolled scenario (R^2=1 for the 2008 costs because the analysis was based on only two data points):

$$\text{Total capital investment (1999 dollars)} = 72169 \times (\text{MMBtu/hr})^{\wedge\,0.66} \quad (R^2=0.99)$$

$$\text{Total annual cost (1999 dollars)} = 17551 \times (\text{MMBtu/hr})^{\wedge\,0.72} \quad (R^2=0.98)$$

$$\text{Total capital investment (2008 dollars)} = 46492 \times (\text{MMBtu/hr})^{\wedge\,0.82} \quad (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 8704 \times (\text{MMBtu/hr})^{\wedge\,0.86} \quad (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of steam injection are assumed to be the same as noted above in the discussion of costs for SCR and water injection.

3.3.6 SCR and Dry Low NOx Combustion; Gas Turbines—Natural Gas (NSCRDGTNG)

Updated costs for combined SCR and DLN combustion control systems were estimated in 1999 dollars for all turbine sizes, 2007 dollars for small turbines, and 2008 dollars for large turbines. The 1999 costs were estimated by combining the separate costs for DLN combustion and SCR provided by Onsite Sycom Energy Systems (OSEC, 1999). The 2007 costs were estimated by combining SCR costs developed by Energy and Environmental Analysis in a report prepared for EPA with the OSEC costs for DLN combustion in 1999 dollars, escalated to 2007 dollars (EEA, 2008). Similarly, costs in 2008 dollars were estimated by combining SCR costs developed by EmeraChem Power in an analysis for the Bay Area Air Quality Management District with escalated DLN combustion costs (ECP, 2008). The EEA analysis provided only capital costs; therefore, we estimated annual costs using the same factors provided in ECP's analysis of costs in 2008 dollars. For both the 2007 and 2008 cost estimates, DLN capital costs and capital recovery were escalated from 1999 dollars using the CEPCI, and annual parts and repairs costs were assumed to be the same in all three years.

Table 3-7 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus dry low NOx combustion on natural gas-fired combustion turbines. Table 3-7 also presents revised incremental costs of SCR relative to a RACT baseline of steam injection for the different categories of turbines. Note that the SCR outlet NOx level was assumed to be 2.5 ppmvd in the ECP analysis, which results in an overall control efficiency of 98 percent versus the 94 percent for the OSEC analyses. We also used an outlet concentration of 2.5 ppmvd to estimate emissions to use with EEA's 2007 costs. The ECP and EEA analyses did not specify inlet NOx emissions concentrations to the SCR; therefore, we assumed 25 ppmvd, as in other DLN analyses. We also assumed an average uncontrolled emissions level of 160 ppmvd for all models so that the overall control efficiency of the DLN combustion plus the SCR was 98 percent. Note that the incremental costs in 1999 dollars are significantly higher than those for SCR following water injection and steam injection; this is due to the inlet concentration being 25 ppmvd for this analysis and 42 ppmvd for water injection and steam injection.

Table 3-7. Summary of Cost Effectiveness and Supporting Data for SCR Plus DLN Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of DLN, $/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	134	<365	9	1,800	2.9	11,900
Small (26.8)	1999	174	>365	9	990	3.6	6,320
Large (161)	1999	210	>365	9	390	4.2	3,340
Small (1–10.2)	2007	160[a]	<365	2.5	2,910	4.3	18,900
Small (25)	2007	160[a]	>365	2.5	1,460	3.8	7,510
Large (50–180)	2008	160[a]	>365	2.5	1,040	4.5	5,560

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in each analysis, the best fit trend lines are represented by the following power equations for uncontrolled scenarios (R^2=1 for the 2008 costs because the analysis was based on only two data points, and note that the R^2 for the 2007 equations is not meaningful because the DLN portion of the costs are based on a regression equation instead of independent, model-specific data):

$$\text{Total capital investment (1999 dollars)} = 24854 \times (\text{MMBtu/hr})^{0.79} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 12725 \times (\text{MMBtu/hr})^{0.69} \quad (R^2=1.0)$$

$$\text{Total capital investment (2007 dollars)} = 187647 \times (\text{MMBtu/hr})^{0.54} \quad (R^2=1.0)$$

$$\text{Total annual cost (2007 dollars)} = 2782 \times (\text{MMBtu/hr}) + 167494 \quad (R^2=1.0)$$

$$\text{Total capital investment (2008 dollars)} = 14790 \times (\text{MMBtu/hr})^{0.97} \quad (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 5263.5 \times (\text{MMBtu/hr})^{0.90} \quad (R^2=1.0)$$

The equations to estimate incremental costs for SCR relative to a RACT baseline of dry low NOx combustion in 1999 dollars and 2008 dollars are assumed to be the same as noted in Section 3.3.4 for incremental costs relative to a RACT baseline of water injection. Incremental costs for SCR relative to a RACT baseline of water injection in 2007 dollars are estimated using the following equations:

$$\text{Total capital investment (2007 dollars)} = 210883 \times (\text{MMBtu/hr})^{0.46} \quad (R^2=1.0)$$

$$\text{Total annual cost (2007 dollars)} = 1894 \times (\text{MMBtu/hr}) + 185570 \quad (R^2=0.99)$$

3.3.7 Water Injection; Gas Turbines—Oil (NWTINGTOL)

No new data are available on costs of water injection for oil-fired combustion turbines. However, because the water injection costs for natural gas-fired turbines were determined to be essentially the same in 1999 as in 1990, we assume the same would be true for water injection on oil-fired turbines; the costs for both types of turbines also were the same in the 1993 ACT analysis. Therefore, we recommend continuing to base costs on the results of the 1993 ACT analysis, but to update the cost year from 1990 to 1999. In addition, we changed the size of the large model in the ACT analysis from 83.3 MW to 84.7 MW because it appears the incorrect model was used in the ACT analysis. As for the natural gas-fired turbines, we also recommend splitting the single record for small sources into two records—one for source with uncontrolled NOx emissions <365 tpy, and the other for sources with uncontrolled NOx emissions >365 tpy. The resulting cost effectiveness values for the turbines with uncontrolled NOx emissions <365 tpy and >365 tpy are $1,630/ton of NOx and $960/ton of NOx, respectively. The capital to annual cost ratios also change slightly.

As for other control technologies, the constants in the equations to estimate total capital costs and total annual costs differ from those in the regression analyses performed in Excel. In this case, the differences are small, but we recommend revising the constants so that all equations are developed based on the same approach. The revised equations for both the uncontrolled and RACT baseline scenarios are:

$$\text{Total capital investment (1999 dollars)} = 43255 \times (\text{MMBtu/hr})^{0.60} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 6796.8 \times (\text{MMBtu/hr})^{0.80} \quad (R^2=1.0)$$

3.3.8 SCR and Water Injection; Gas Turbines—Oil (NSCRWGTNG)

SCR costs were developed in a BACT analysis for a 48 MW oil-fired combustion turbine (FMPA, 2004). Because water injection costs in 2004 dollars are not available, we calculated costs in 1999 dollars as described above for the water injection option, and then estimated costs in 2004 dollars by scaling up the 1999 capital costs (and capital recovery) using the CEPCI; other annual operating and maintenance costs were assumed to be unchanged. We used the SCR capital cost as presented in the FMPA analysis, but we made several changes to the annual costs. Although the original values may have been appropriate for the specific application evaluated by FMPA, the following changes were made to be consistent with the calculations for other controls in this analysis:

- Estimated O&M costs assuming operation for 8,000 hr/yr instead of 4,422 hr/yr.
- Excluded cost for one week of lost power generation while catalyst is being replaced, assuming that catalyst replacement can be performed during scheduled annual downtime.
- Reduced sales tax and freight cost for catalyst from 12.25 percent of the purchased cost to 8 percent of the purchased cost.
- Deleted capital recovery cost for catalyst because the catalyst is replaced annually.

- The reported annual cost for ammonia was based on a stoichiometric ratio of 1.4 (possibly because they assumed a significant generation of NO2 relative to NO). They also applied a factor of 1.05, apparently to account for ammonia slip, as in the Control Cost Manual procedures for SCR on boilers. However, both factors should not be needed. For this analysis, we used just the 1.05 factor (also used the reported unit cost of $750/ton of ammonia, which may have been high for 2004).

- Reduced the property tax factor from 2.75 percent of the TCI to 1 percent of the TCI.

Table 3-8 summarizes the recommended cost effectiveness and capital to annual cost ratios values for implementing SCR plus water injection on oil-fired combustion turbines. Table 3-8 also presents incremental costs of SCR relative to a RACT baseline of water injection. The 1990 costs are essentially the same as the costs currently in the CMDB, except that we recommend splitting the one record for small sources into two records.

Table 3-8. Summary of Cost Effectiveness and Supporting Data for SCR Plus Water Injection (WI) for Oil-Fired Turbines

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, $/ton NOx
		Avg. ppmvd	tpy				
Small (3.3)	1990	179	<365	18	3,200	2.9	7,620
Small (26.3)	1990	211	>365	18	1,320	2.3	2,450
Large (84)	1990	228	>365	18	1,000	2.4	2,210
Large (48)	2004	200[a]	>365	5	1,560	2.3	4,790

[a]The referenced analysis did not report an uncontrolled emissions level. The value used in this analysis is the average of the uncontrolled emissions concentrations for oil-fired model turbines in the 1993 ACT.

Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for the uncontrolled scenario:

$$\text{Total capital investment (1990 dollars)} = 95837 \times (\text{MMBtu/hr})^{0.62} \quad (R^2=0.99)$$

$$\text{Total annual cost (1990 dollars)} = 25990 \times (\text{MMBtu/hr})^{0.70} \quad (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of water injection are:

$$\text{Total capital investment (1990 dollars)} = 4744 \times (\text{MMBtu/hr}) + 368162 \quad (R^2=1.0)$$

$$\text{Total annual cost (1990 dollars)} = 1522.5 \times (\text{MMBtu/hr}) + 142643 \quad (R^2=1.0)$$

We could not develop equations for this control system in 2004 dollars because 2004 data are available for only one turbine, and thus are insufficient for this purpose.

3.3.9 Water Injection; Gas Turbines—Jet Fuel (NWTINGTJF)

The current CMDB assumes costs for jet fuel-fired turbines are the same as for oil-fired turbines. Thus, we recommend the same changes for jet fuel fired turbines as noted above for oil-fired turbines.

3.3.10 SCR and Water Injection; Gas Turbines—Jet Fuel (NSCTWGTJF)

The current CMDB assumes costs for jet fuel-fired turbines are the same as for oil-fired turbines. Thus, we recommend the same changes for jet fuel fired turbines as noted above for oil-fired turbines.

3.3.11 Applicable Control Measures for Gas Turbine SCCs

The first column in Table 3-9 lists all of the gas turbine SCCs that are associated with one or more gas turbine control measures in the CMDB table called "Table 03_SCCs." In addition, the last seven SCCs in Table 3-9 are additional gas turbine SCCs that are not currently assigned any NOx control measures in the CMDB. These seven SCCs, as well as many of the others at the top of Table 3-9, were identified with NOx emissions in an EPA query of the NEI for facilities in the Ozone Transport Group Assessment Region (i.e., 37 states that are partially or completely to the east of 100^{o}W longitude). The first 11 control measures in column headings in Table 3-9 are the gas turbine control measures that are currently in the CMDB; the last three column headings are the new control measures identified in this review and described in Section 3.2 of this report.

Each control measure that was determined to be applicable for a specific SCC is identified by either an "E" or an "N" in the cell at the intersection of the applicable SCC row and the control measure column. An "E" means the control measure is already listed in the CMDB for the particular SCC, and we concur with that designation. An "N" means the control measure is not currently linked to a particular SCC, but we recommend adding this link in the database. In some cases, we recommend applying new links between existing control measures and existing SCCs. For example, some of the SCCs are for turbines that are fired with relatively uncommon fuels such as landfill gas or gasoline. We have not located any analyses that determined the applicable controls and related costs for gas turbines fired with such fuels. In order to conduct CoST modeling analyses for these turbines, the most representative available control measures

Table 3-9. Recommended Control Measures for Gas Turbine SCCs

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC[d]													
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
20200101	ICE	Ind	Distillate Oil (Diesel)	Turbine	E	E												
20200103	ICE	Ind	Distillate Oil (Diesel)	Turbine: Cogeneration	E	E												
20200108	ICE	Ind	Distillate Oil (Diesel)	Turbine: Evap Losses	D	D												
20200109	ICE	Ind	Distillate Oil (Diesel)	Turbine: Exhaust	E	E												
20200201	ICE	Ind	Natural Gas	Turbine					E	E	E	E	E	E	D	N	N	N
20200203	ICE	Ind	Natural Gas	Turbine: Cogeneration					E	E	E	E	E	E	D	N	N	N
20200208	ICE	Ind	Natural Gas	Turbine: Evap Losses					D	D	D	D	D	D	D			
20200209	ICE	Ind	Natural Gas	Turbine: Exhaust					E	E	E	E	E	E	D	N	N	N
20200701	ICE	Ind	Process Gas	Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20200705	ICE	Ind	Process Gas	Refinery Gas: Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20200713	ICE	Ind	Process Gas	Turbine: Evap Losses											D			
20200714	ICE	Ind	Process Gas	Turbine: Exhaust					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20200901	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine			E	E										
20200908	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine: Evap Losses			D	D										
20200909	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine: Exhaust			E	E										
20201008	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Evap Losses											D			

(continued)

Table 3-9. Recommended Control Measures for Gas Turbine SCCs (continued)

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC[d]													
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
20201009	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Exhaust	N[e]	N[e]									D			
20201011	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine	N[e]	N[e]									D			
20201013	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Cogeneration	N[e]	N[e]									D			
20300102	ICE	C/I	Distillate Oil (Diesel)	Turbine	E	E												
20300108	ICE	C/I	Distillate Oil (Diesel)	Turbine: Evap Losses	D	D												
20300109	ICE	C/I	Distillate Oil (Diesel)	Turbine: Exhaust	E	E												
20300202	ICE	C/I	Natural Gas	Turbine					E	E	E	E	E	E	D	N	N	N
20300203	ICE	C/I	Natural Gas	Turbine: Cogeneration					E	E	E	E	E	E	D	N	N	N
20300208	ICE	C/I	Natural Gas	Turbine: Evap Losses					D	D	D	D	D	D	D			
20300209	ICE	C/I	Natural Gas	Turbine: Exhaust					E	E	E	E	E	E	D	N	N	N
20300701	ICE	C/I	Digester Gas	Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20300708	ICE	C/I	Digester Gas	Turbine: Evap Losses											D			
20300709	ICE	C/I	Digester Gas	Turbine: Exhaust					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20300801	ICE	C/I	Landfill Gas	Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20300808	ICE	C/I	Landfill Gas	Turbine: Evap Losses											D			
20300809	ICE	C/I	Landfill Gas	Turbine: Exhaust					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20400301	ICE	ET	Turbine	Natural Gas					N	N	N	N	N	N	D	N	N	N
20400304	ICE	ET	Turbine	Landfill Gas					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]

(continued)

Table 3-9. Recommended Control Measures for Gas Turbine SCCs (continued)

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC[d]													
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
50100420	WD	SWD-G	Landfill Dump	Waste Gas Recovery: GT					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20201609	ICE	Ind	Methanol	Turbine: Exhaust	N[e]	N[e]												
20201701	ICE	Ind	Gasoline	Turbine	N[e]	N[e]												
20300901	ICE	C/I	Kerosene/Naphtha (Jet Fuel)	Turbine: JP-4			N	N										
20400302	ICE	ET	Turbine	Diesel/Kerosene	N	N												
20400303	ICE	ET	Turbine	Distillate Oil	N	N												
20400305	ICE	ET	Turbine	Kerosene/Naphtha			N	N										
20400399	ICE	ET	Turbine	Other Not Classified[f]	N[e]	N[e]												

[a]SCCs in regular font are associated with one or more gas turbine control measures in the current CMDB. The SCCs in bold font represent gas turbine activities that were identified with NOx emissions in the Ozone Transport Assessment Group Region analysis but are not associated with gas turbine control measures in the current CMDB.

[b]ICE means "Internal Combustion Engines" and WD means "Waste Disposal."

[c]Ind means "Industrial," C/I means "Commercial/Institutional," ET means "Engine Testing," and SWD-G means "Solid Waste Disposal-Government."

[d]An "E" means the control measure is currently associated with the SCC in the CMDB, and no changes are recommended. A "D" means the control measure is currently associated with the SCC, but this control measure should be deleted because it is not appropriate for the SCC. An "N" means the control measure is not currently associated with the SCC in the CMDB, but adding it is recommended.

[e]The control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

[f]The fuel type is unknown. For the purposes of this analysis it is assumed to be a liquid because most of the emissions identified for the engine testing SCCs in the analysis done in the Ozone Transport Assessment Group Region were from liquid fuel-fired turbines.

should be assigned. For turbines that burn miscellaneous gaseous fuels, the most representative control measures are those for natural gas-fired turbines. Similarly, for turbines that burn miscellaneous liquid fuels, the most representative available control measures are those for oil-fired turbines. The description field in the CMDB table called "Table 02_Efficiencies" could be revised to indicate that the control measures for natural gas units are assumed to be applicable for all gaseous fuel fired units, and the control measures for oil-fired units are assumed to be applicable for all liquid fuel-fired units (note that the separate control measures already in the CMDB for jet fuel-fired turbines are also based on the data for oil-fired units).

Finally, gas turbine SCCs for evaporative losses from turbine fuel storage and delivery systems are associated with NOx control measures in the current CMDB. We recommend deleting these NOx control measure/SCC records from the CMDB table called "Table 03_SCCs" because there should be no NOx emissions from the sources represented by these SCCs. These control measure/SCC combinations are identified with a "D" in the applicable cells in Table 3-9.

3.4 Example Emission Limits for NonEGU Combustion Turbines

NonEGU combustion turbines are subject to several emission regulations, including NSPS in 40 CFR part 60 and various state regulations. Example emission limits in state regulations are presented in Table 3-10.

Table 3-10. NOx Emissions Limits for NonEGU Combustion Turbines in New York

State	Type of Service	Type of Combustion Turbine Operating Cycle	Emission Limit	Effective Date
New York[a]	Any—gaseous fuel	Combined cycle	42 ppmdv (at 15% O2)	Current
		Simple cycle or regenerative cycle	50 ppmdv (at 15% O2)	Current
	Any—oil-fired	Combined cycle	65 ppmdv (at 15% O2)	Current
		Simple cycle or regenerative cycle	100 ppmdv (at 15% O2)	Current

[a]The requirements apply to combustion turbines with a maximum heat input rate greater than or equal to 10 million Btu per hour at major sources of NOx emissions. The specified limits apply until July 1, 2014; beginning on July 1, 2014, owners/operators must submit a proposal for RACT (NYCRR, 2014).

3.5 References

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SECTION 4
GLASS MANUFACTURING SECTOR

4.1 Introduction

The control cost database separates the glass manufacturing sector into four different types; flat glass, container glass, pressed glass, and general glass manufacturing. The CMDB listed six different control technologies for NOx emissions which were all reviewed in 2006 and included cullet preheat, oxy-firing, electric boost, low NOx burners, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). A literature and internet search was conducted to find any new control technologies for NOx or any updates to existing controls regarding cost and efficiencies. Operating permits for some glass manufacturing plants were reviewed and control system vendors were also contacted for information. A brief summary of data from each reference reviewed in included in the spreadsheet "CoST_Glass Mfg.xlsx."

4.2 Example NOx Regulatory Limits

4.2.1 Wisconsin

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.[1]

4.2.2 New Jersey

Commercial container glass, specialty container glass, borosilicate recipe glass, pressed glass, blown glass, and fiberglass manufacturing furnaces: 4.0 lbs/ton glass removed. Flat glass manufacturing furnaces: 9.2 lbs/ton glass removed.

4.2.3 New York

NOx emissions are covered under NY's case-by case RACT regulations.

4.3 Recommended Additions

The following NOx controls are recommended additions for the glass manufacturing industry that are not currently in the control cost database, and a tabular summary of the costs is presented in Table 4-1.

- Electric Boost—Three entries for electric boost controls were in the CMDB for container, flat, and pressed glass manufacturing. A cost estimate for electric boost was found for "general" glass manufacturing (DOE, 2002), since the CMDB did not have a "general" entry for electric boost controls, an entry for "Electric Boost; Glass Manufacturing—General" was added with a new abbreviation of NELBOGMGN. The

[1] http://dnr.wi.gov/About/NRB/2007/January/01-07-3A4.pdf

reference provided an annualized cost of $7,100 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace operating with an emission rate of 8-lb NOx per ton glass produced and a NOx removal efficiency of 30 percent. Since the reference did not provide capital costs, the capital to annual cost ratio could not be determined, and the capital recovery factor was assumed to be the same as the electric boost entries for container, flat, and pressed glass (i.e., 0.1424, assuming equipment life of 10 years).

- Oxy-firing—Three entries for oxy-firing were in the CMDB for container, flat, and pressed glass manufacturing. Similar to electric boost controls, an updated cost estimate for oxy-firing was found for "general" glass manufacturing (DOE, 2002); since the CMDB did not have a "general" entry for oxy-firing, an entry for "OXY-Firing; Glass Manufacturing—General" was added to the CMDB with a new abbreviation of NOXYFGMGN. The reference provided an annualized cost of $2,352 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace emitting 8-lb NOx per ton glass produced and a NOx removal efficiency of 85 percent.[1] Since the capital costs were not provided the capital to annual cost ratio and the capital recovery factor were assumed to be the same as the oxy-firing entries for container, flat, and pressed glass, which all had the same values.

- Catalytic Ceramic Filter—This new control technology for NOx reduction was not previously in the database and was added for flat glass manufacturing with a new abbreviation of CATCFGMFT. A vendor was contacted for information (2013 Vendor Quote). The minimum and maximum cost per ton estimates were based on regenerative gas-fired furnace with pull rates of 600 tons per day and 490 tons per day, respectively. The estimate provided by the vendor included capital cost, annualized capital costs, and annual operational cost in 2013 dollars; it also included NOx reductions based on a 95 percent NOx efficiency.

Table 4-1. Summary of Cost Effectiveness and Supporting Data for Recommended Additions

Technology	Furnace Production Rate (ton/day)	Cost Year	NOx Removal Efficiency (%)	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
Electric Boost (general)	250	2002	30	7,100	N/A[a]
Oxy-firing General	250	2002	85	2,352	2.7
Catalytic Ceramic Filter	490	2013	95	1,045	4.6
	600	2013	95	997	4.6

[a]The ratio cannot be calculated because capital costs are not available.

4.4 Recommended Changes

Changes to the CMDB are recommended for the following three types of control measures, which are also summarized in Table 4-2.

- Low NOx Burner General—Three entries for Low NOX burners were in the cost database for container, flat, and pressed glass manufacturing. An updated cost estimate for low NOx burners for flat glass and container glass manufacturing (EC, 2013) was found and entries NLNBUGMCN and NLNBUGMFT were updated. The reference provided capital costs and an annualized cost in euros per kilogram of NOx removed which was converted to dollars per ton of NOx. For flat glass the minimum cost per ton estimate was based on a 900 ton per day gas fired furnace, and the maximum cost per ton estimate was based on a 500 ton per day gas fired furnace. For container glass the minimum cost per ton estimate was based on 450 ton per day gas fired furnace, and the maximum cost per ton estimate was based on a 200 ton per day gas fired furnace. The capital recovery factor and the capital to annual cost ratio were also updated. We also recommend changing the equipment life for low NOx burners on flat glass furnaces from 3 years to 10 years (EC, 2013).

  Additionally, equations for low NOx burners were added for entries NLNBUGMCN and NLNBUGMFT to "Table 04_Equations" of the CMDB based on the best fit trend lines of the total capital investment and total annual cost for the facilities with the production levels described above, the best fit trend line results were as follows:

  NLNBUGMCN (The correlation coefficients are high because the data are from a single source, and they may reflect data points from a correlation performed by that source)

  Total capital investment (2007 dollars) = 30,930 x $(\text{tons/day})^{0.45}$ ($R^2 = 0.99$)

  Total annual cost (2007 dollars) = 9,377 x $(\text{tons/day})^{0.40}$ ($R^2 = 0.99$)

  NLNBUGMFT (The correlation coefficients are a perfect 1.0 because only two data points are available)

  Total capital investment (2007 dollars) = 527 x (tons/day) + 664,557 ($R^2 = 1.0$)

  Total annual cost (2007 dollars) = 132x (tons/day) + 150,105 ($R^2 = 1.0$)

- Cullet Preheating—Two entries for cullet preheating controls were in the cost database for container and pressed glass manufacturing. An updated annualized cost per ton value and NOx efficiency for pressed and container glass entries (IT, 2002) were found and updated for entries NCLPTGMCN and NCUPHGMPD. The reference provided an annualized cost of $5,000 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace emitting 8-lb NOx per ton glass produced and a NOx removal efficiency of 5 percent.[1] Since the reference did not

[1] Annualized cost includes capital and O&M costs and is based on 2002 dollars.

provide capital costs separately, the capital to annual cost ratio and the capital recovery factor were not updated. Additionally, based on information from EPA's OECA staff, class entries for cullet preheating should be changed from "known" to "emerging" in Table 01_Summary of the CMDB because this control measure is technically feasible but has rarely been implemented.[1]

- Selective Catalytic Reduction—Three entries for selective catalytic reduction were in the CMDB for container, flat, and pressed glass manufacturing. An updated cost estimate for SCR for flat glass and container glass manufacturing (EC, 2013) was found, and entries NSCRGMCN and NSCRGMFT were updated. The reference provided capital costs and an annualized cost in euros per kilogram of NOx removed which was converted to dollars per ton of NOx.[2] For flat glass the minimum and maximum cost per ton estimates were based on a 900 and 500 ton per day gas fired furnace, respectively. For container glass the minimum and maximum estimates were based on a 450 and 200 ton per day gas fired furnaces, respectively. The capital to annual cost ratio were also updated.

  Equations for SCR were added for entries NSCRGMCN and NSCRGMFT to Table 4 of the CMDB based on the best fit trend lines of the total capital investment and total annual cost for the facilities with the production levels described above, the best fit trend line results were as follows:

  NSCRGMCN (The correlation coefficients are high because the data are from a single source, and they may reflect data points from a correlation performed by that source)

  Total capital investment (2007 dollars) = 79,415 x (tons/day) $^{0.51}$ (R^2 = 0.99)

  Total annual cost (2007 dollars) = 643 x (tons/day) + 135,302 (R^2 = 1.0)

  NSCRGMFT (The correlation coefficients are a perfect 1.0 because only two data points are available)

  Total capital investment (2007 dollars) = 3681 x (tons/day) + 1.0E+06 (R^2 = 1.0)

  Total annual cost (2007 dollars) = 842 x (tons/day) + 424,930 (R^2 = 1.0)

1 Personal communication. Katie McClintock, US EPA/OCEA, with Larry Sorrels, US EPA/OAR/OAQPS, Feb. 13, 2014.

2 Conversion based on 2008 average exchange rate of 0.711. Source: http://www.irs.gov/Individuals/International-Taxpayers/Yearly-Average-Currency-Exchange-Rates

Table 4-2. Summary of Cost Effectiveness and Supporting Data for Recommended Additions

Technology	Furnace Production Rate (ton/day)	Cost Year	NOx Removed (tons/year)	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
NLNBUGMCN	200	2007	66	1,365	4.2
	450	2007	100	1,072	4.3
NLNBUGMFT	500	2007	371	574	4.2
	900	2007	611	447	4.3
NCLPTGMCN	250	2002	5%	5,000	4.5
NCUPHGMPD	250	2002	5%	5,000	4.5
NSCRGMCN	200	2007	121	2,169	4.5
	450	2007	251	1,684	4.2
NSCRGMFT	500	2007	886	957	3.4
	900	2007	1,383	855	3.7

4.5 Recommended Deletions

- Selective Non-Catalytic Reduction—Three entries for selective non-catalytic reduction were in the cost database for container, flat, and pressed glass manufacturing. Based on conversations between EPA and OECA staff, SNCR entries for glass manufacturing should be removed based on recent NSR settlements that indicate SNCR is not a technically feasible control technology for the removal of NOx.[1]

4.6 Updates to Source Classification Codes

- There are twenty applicable SCCs for glass manufacturing as shown in Table 4-3.

- In an analysis of NO_X emissions for the Ozone Transport Assessment Group Region in 2011, fourteen of the SCCs in Table 4-3 were identified. The six SCCs not included in the Ozone Transport Region are shown at the bottom of Table 4-3. Four of the SCCs, 30501401, 30501402, 30501403, and 30501404 are associated with glass manufacturing NO_X controls in the current CMDB.

- Furnaces are the primary source of NOx emissions in the glass manufacturing industry, therefore NOx emission control techniques are typically for point emission sources associated with furnace emissions. The four SCCs identified in the CMDB pertain to four types of melting furnaces; general, flat, container, and pressed. The

[1] Personal communication. Katie McClintock, US EPA/OCEA, with Larry Sorrels, US EPA/OAR/OAQPS, Feb. 13, 2014.

remaining sixteen SCCs in Table 4-3 are not associated with furnaces. Therefore, no changes related to SCCs are recommended for the CMDB.

- For new control techniques added to the CMDB for glass manufacturing, the applicable SCC from Table 4-3 was added to the Description field for each control technique in Table 01_Summary in the CMDB (Table C-1of Appendix C of this report). These related control measures and SCCs should also be added to "Table 03_SCCs" in the CMDB.

Table 4-3. Applicable SCCs for the Glass Manufacturing Industry

SCC Code	SCC Level One	SCC Level Two	SCC Level Three	SCC Level Four
30501401[a]	Industrial Processes	Mineral Products	Glass Manufacture	Furnace/General**
30501402[a]	Industrial Processes	Mineral Products	Glass Manufacture	Container Glass: Melting Furnace
30501403[a]	Industrial Processes	Mineral Products	Glass Manufacture	Flat Glass: Melting Furnace
30501404[a]	Industrial Processes	Mineral Products	Glass Manufacture	Pressed and Blown Glass: Melting Furnace
30501406	Industrial Processes	Mineral Products	Glass Manufacture	Container Glass: Forming/Finishing
30501407	Industrial Processes	Mineral Products	Glass Manufacture	Flat Glass: Forming/Finishing
30501408	Industrial Processes	Mineral Products	Glass Manufacture	Pressed and Blown Glass: Forming/Finishing
30501410	Industrial Processes	Mineral Products	Glass Manufacture	Raw Material Handling (All Types of Glass)
30501411	Industrial Processes	Mineral Products	Glass Manufacture	General **
30501413	Industrial Processes	Mineral Products	Glass Manufacture	Cullet: Crushing/Grinding
30501414	Industrial Processes	Mineral Products	Glass Manufacture	Ground Cullet Beading Furnace
30501416	Industrial Processes	Mineral Products	Glass Manufacture	Glass Manufacturing
30501420	Industrial Processes	Mineral Products	Glass Manufacture	Mirror Plating: General
30501499	Industrial Processes	Mineral Products	Glass Manufacture	See Comment **
SCCs Not Included in the Ozone Transport Assessment Group Region:				
30501405	Industrial Processes	Mineral Products	Glass Manufacture	Presintering
30501412	Industrial Processes	Mineral Products	Glass Manufacture	Hold Tanks **
30501415	Industrial Processes	Mineral Products	Glass Manufacture	Glass Etching with Hydrofluoric Acid Solution
30501417	Industrial Processes	Mineral Products	Glass Manufacture	Briquetting
30501418	Industrial Processes	Mineral Products	Glass Manufacture	Pelletizing
30501421	Industrial Processes	Mineral Products	Glass Manufacture	Demineralizer: General

[a]Denotes SCCs included in the CMDB.

4.7 References

DOE, 2002. Oxygen Enriched Air Staging a Cost-effective Method For Reducing NOx Emissions. U.S. Department of Energy. Office of Industrial Technologies. April 2002. http://www1.eere.energy.gov/manufacturing/resources/glass/pdfs/airstaging.pdf

EC, 2013. Best Available Techniques (BAT) Reference Document for the Manufacture of Glass. European Commission 2013. http://eippcb.jrc.ec.europa.eu/reference/BREF/GLS_Adopted_03_2012.pdf

Vendor Quote 2013 – Confidential Business Information

SECTION 5
LEAN BURN ENGINES

The CMDB includes the following NO_X emissions control measures for Lean Burn Engines:

- Air to fuel ratio (AFR) (achieves 20 percent reduction)
- Air to fuel ratio (AFR) and Ignition retard (IR) (achieves 30 percent reduction)
- Ignition retard (IR) (achieves 20 percent reduction)
- Low emission combustion (achieves 87 percent reduction)
- Low emissions combustion, low speed (achieves 87 percent reduction)
- Low emissions combustion, medium speed (achieves 87 percent reduction)
- Nonselective catalytic reduction (NSCR) (achieves 90 percent reduction)
- Selective catalytic reduction (SCR) (achieves 90 percent reduction)
- Selective noncatalytic reduction (SNCR) (achieves 90 percent reduction)

Based on the literature review and the new cost data identified for Lean Burn control technologies, several changes to the CMDB are recommended. No changes to existing records in CMDB are recommended. The following sections outline the additions and other comments recommended for the CMDB in relation to NO_X emissions from Lean Burn Engines.

5.1 Literature Search

In order to update the existing control measures database, a literature search was conducted for articles and papers published since 2008 (to include 2008 through August 2013) using the following terms:

- engine
- lean burn
- cost
- NOx or "nitrogen oxides"
- scr or "selective catalytic reduction"
- turbocharge

- air/fuel ratio
- layered combustion
- high energy ignition
- high pressure fuel injection
- “low emission control” or LEC
- electronic engine control
- combustion modification
- timing
- exhaust gas recirculation
- lean NOx catalyst
- lean NOx trap
- control efficiency
- emission reduction

The literature search identified a total of 19 references, and the abstracts for these references were reviewed. Three references of potential interest were identified and two of these were obtained for review in the lean burn engine control device study.

5.2 Document Review

A brief summary of data from each reference reviewed in included in the spreadsheet “CoST_leanburn.xlsx,” in worksheet “Overall Sum—New Ref Review.” The information and data available from each reference is provided in table format, along with indication of whether the data were used or not.

There are 6 control technique additions to be added to the CMDB from 5 references.

The recommended additions include:

- Low Emission Combustion, LEC (for natural gas engines);
- Layered Combustion, LC (for 2 stroke natural gas engines);
- Layered Combustion, LC (for 2 stroke Large Bore natural gas engines);

- Air to Fuel Ratio Controller, AFRC;
- Selective Catalytic Reduction, SCR (for 4 stroke natural gas engines); and
- SCR (for diesel engines).

Recent cost data for these control techniques were available from reports dated 2001 through 2012.

The references for the added control techniques are included on the "**Table 06 References**" worksheet and are as follows:

OTC 2012. Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final. October 17, 2012.

SJVAPCD 2003. RULE 4702—Internal Combustion Engines—Phase 2. Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2). San Joaquin Valley Air Pollution Control District. July 17, 2003. www.arb.ca.gov/pm/pmmeasures/ceffect/rules/sjvapcd_4702.pdf

CARB 2001. Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

EPA 2010. Alternative Control Techniques Document: Stationary Diesel Engines. March 5, 2010.

PA DEP 2013. Technical Support Document General Permit GP-5. Pennsylvania Department of Environmental Protection, Bureau of Air Quality. January 31, 2013.

5.3 Low Emission Combustion (LEC) (NLECICENG)

The costs and cost effectiveness for applying LEC to natural gas Lean Burn engines are obtained from the document *Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2)* (SJVAPCD 2003). Information was provided on Capital costs, Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-1 for LEC along with changes in assumptions for the current analysis.

LEC are described as retrofit kits that allow engines to operate on extremely lean fuel mixtures to minimize NOx emissions. The LEC retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines), (2) Precombustion chamber (on larger engines), lower cost, simple versions, (3) Turbocharger, (4) High energy ignition system,

Table 5-1. LEC for Natural Gas Lean Burn Engines

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 80%	None.
Capital costs: provided for multiple models	None.
Annual Costs	
Equipment life: 10 yr	None.
Interest rate: 10%	Interest rate: 7%
Operating hours: 2000 hr/yr	None.
Emission rate, uncontrolled: 740 ppmv	Emission rate, uncontrolled: Assumed mid to upper end hp rating for each model.
Emission rate, controlled: 80% reduction	None.
Annualized equipment cost: provided for multiple model sizes	CRF: 0.1424
Annual O&M cost: assumed $0.	None.

(5) Aftercooler, and (6) Air to fuel ratio controller. (A discussion of individual technologies is provided in Appendix B of the original reference, pp. B-1 to B-28). No detail was provided on the exact combination of combustion modifications included in the example cost analysis; some references indicate that LEC on larger engines often includes a PCC (p.B-10) (CARB 2001). LEC are known or demonstrated control techniques for lean burn engines. An 80 percent NOx emission reduction can be achieved by LEC with little or no fuel penalty (in fact, LEC technologies are expected to decrease fuel consumption because they result in leaner burning engine, though the costs do not account for fuel consumption decrease). The original reference assumed an 80 percent reduction in the cost example.

Capital and annual costs were provided for multiple size ranges of engines. The capital costs ranged from $14,000 to $256,000. Costs for the 1000 to 3000 hp model were given as $40,000 to $256,000, and a mid-range cost of $148,000 was assumed in the current analysis. The total annual costs ranged from $2,000 to $21,000 (these costs are very similar to the costs calculated in the original reference analysis). The original reference assumed there are no annual operation and maintenance costs incurred from the combustion modification technologies, and the only annual cost provided is for annualized capital costs. No emission reductions are provided in the document (however the final cost effectiveness values are provided and the reduction assumed in the original analysis can be back-calculated). In the current analysis, a hp rating based on the middle or upper end of each size range was assumed for estimating the uncontrolled NOx emissions. An estimate of emissions was made in the current analysis. Uncontrolled NOx emissions were estimated based on an uncontrolled NOx concentration of 740 ppmv (this equates to approximately 9 g/bhp-hr), the operating hours were provided as 2000 hr/yr in the original reference, and controlled emissions were estimated based on 80 percent reduction as stated in the reference. Uncontrolled NOx emissions ranged from 1.1 to 34 tpy for the models, and the NOx reductions ranged from 0.90 to 27 tpy for the models.

The current analysis shows a cost effectiveness of $2,200/ton of NOx reduction to $780/ton for 2000 hr/yr operation, and the average cost effectiveness across all the models is $1,000/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited reference, 2001$.

Based on the cost calculations for engines of varying hp, the following equations were developed for the capital cost and annual costs for LEC on natural gas Lean Burn engines:

$$\text{Capital cost} = 16019\ e^{0.0016\ \text{x}\ (\text{hp})}$$
$$\text{Annual cost} = 2280.8\ e^{0.0016\ \text{x}\ (\text{hp})}$$

The R^2 value for these equations is 0.96. These equations should be included in the CoST database file under a new equation type.

See the cost calculations in worksheet “LEC (CARB)-2001” of the Excel file.

5.4 Layered Combustion (LC), 2 Stroke (NLCICE2SNG)

The costs and cost effectiveness for applying LC to natural gas Lean Burn engines (2 stroke) are obtained from the document *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions* (OTC 2012). Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-2 for LC for 2 stroke engines, along with changes in assumptions for the current analysis.

LC consists of multiple combustion modification technologies. The combustion modifications included in this example are related to (1) Air supply; (2) Fuel supply, (3) Ignition, (4) Electronic controls, and (5) Engine monitoring (a discussion of individual technologies is provided on pp. 17 to 19 for 2 stroke Lean Burn engines). No significant detail was provided on which specific combustion modification technologies were applied. In the example study, 3 of the most representative manufacturer and models of 2 stroke Lean Burn engines used for integral compressors were selected for evaluation; these 3 engines were Cooper GMVH-10 2250 hp,

Table 5-2. LC for Natural Gas Lean Burn Engines, 2-stroke

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: Not provided.	Control efficiency: derived value is 97% (this is high)
Capital costs: based on cited ERLE 2009 project (First unit upgrade costs)	Capital costs: used average based on the provided range for each make/model engine.
Annual Costs	
Equipment life: Not provided.	Equipment life: 10 yr
Interest rate: Not provided.	Interest rate: 7%
Operating hours: Not provided.	Operating hours: 2000 hr/yr
Emission rate, uncontrolled: Not provided	Emission rate, uncontrolled: 16.8 g/bhp-hr
Emission rate, controlled: 0.5 g/bhp-hr	None.
Annualized equipment cost: Not provided.	CRF: 0.1424
Annual O&M cost: Not provided.	Annual O&M cost: $0.

Clark TLA-6 2000 hp, and Cooper GMW-10 2500 hp (cited ERLE 2009 report "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy 0.5 g/bhp-hr NOx"). LC are known or demonstrated control techniques for lean burn, 2 stroke engines. A NOx emissions rate of 0.5 g/bhp-hr was achieved. The OTC 2012 document provided an estimate of the capital cost range for retrofitting technologies to achieve the outlet NOx limit for each engine. An average cost based on the range was estimated for each engine and used in the current analysis. Details on the buildup of these costs are not provided in the OTC 2012 document. No annual costs are provided in the document. No emission reductions are provided in the document.

Based on the review of other references in this analysis, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (CARB 2001). Because no emission reduction data were provided, an estimate of emissions was made in the current analysis. Uncontrolled NOx emissions were assumed to be 16.8 g/bhp-hr (EPA 2003), controlled emissions were 0.5 g/bhp-hr as stated in the reference, and the operating hours were assumed to be 2000 hr/yr (this assumption is consistent with the LEC operating hours in the CARB 2001 document).

Uncontrolled NOx emissions for the 3 similar sized engines ranged from 74 to 93 tpy, and the NOx reductions ranged from 72 to 90 tpy.

Based on the 3 make and model engines, the average cost was estimated to be $2,800,000 for approximately 2250 hp engines (average hp of the 3 units), and the average total annual cost was estimated to be $390,000. The average cost effectiveness is $4,900/ton of NOx reduction for 2000 hr/yr operation.

The cost year is not provided in the reference; we assumed the cost year is the date of the cited Cameron 2010 retrofit project, 2010$.

See the cost calculations in worksheet "Overall Sum—New Ref Review" of the Excel file, rows 21 through 25.

5.5 Layered Combustion (LC), Large Bore, 2 Stroke, Low Speed (NLCICE2SLBNG)

The costs and cost effectiveness for applying LC to natural gas Lean Burn engines (2 stroke Large Bore) are obtained from the document *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions* (OTC 2012). Large Bore RICE are those with large piston diameters. The larger the bore (or piston diameter), the larger the volume available for engine combustion, and hence the greater the power delivered by the engine. Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-3 for LC for large bore 2 Stroke engines, along with changes in assumptions for the current analysis.

LC consists of multiple combustion modification technologies. The combustion modifications included (1) High pressure fuel injection; (2) Turbocharging, (3) Precombustion chamber, and (4) Cylinder head modifications (a discussion of individual technologies is provided on pp. 18 to 19 for 2 stroke Lean Burn engines). LC are known or demonstrated control techniques for lean burn, large bore, 2 stroke engines. These modifications achieved a NOx emissions rate of 0.5 g/bhp-hr. The OTC 2012 document provided ranges of capital costs for retrofitting combustion modifications for large bore 2 stroke Lean Burn engines from 200 to 11,000 hp (cited Cameron 2011 presentation "Available Emission Reduction Technology for Existing Large Bore Slow Speed Two Stroke Engines." A copy of this presentation was not found.). Details on the buildup of these costs are not provided in the OTC 2012 document. No annual costs are provided in the document. No emission reductions are provided in the document.

Based on the review of other references in this analysis, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (CARB 2001). Because no emission reduction data were provided, an estimate of emissions was made in the current analysis. Uncontrolled NOx

Table 5-3. LC for Natural Gas Lean Burn Engines, Large Bore 2-stroke

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: Not provided.	Control efficiency: derived value is 97% (this is high)
Capital costs: based on cited Cameron 2010 project	None.
Annual Costs	
Equipment life: Not provided.	Equipment life: 10 yr
Interest rate: Not provided.	Interest rate: 7%
Operating hours: Not provided.	Operating hours: 2,000 hr/yr
Emission rate, uncontrolled: Not provided	Emission rate, uncontrolled: 16.8 g/bhp-hr
Emission rate, controlled: 0.5 g/bhp-hr	None.
Annualized equipment cost: Not provided.	CRF: 0.1424
Annual O&M cost: Not provided.	Annual O&M cost: $0.

emissions were assumed to be 16.8 g/bhp-hr (EPA 2003), controlled emissions were 0.5 g/bhp-hr as stated in the reference, and the operating hours were assumed to be 2000 hr/yr (this assumption is consistent with the LEC operating hours in the CARB 2001 document). Uncontrolled NOx emissions were estimated to be 410 tpy for the larger 11,000 hp engines and were estimated to be 7.4 tpy for the smaller 200 hp engines.

For the larger 11,000 hp engines, the current analysis shows a cost effectiveness of $1,500/ton of NOx reduction, and for the smaller 200 hp engines, the cost effectiveness is $38,000/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited Cameron 2010 retrofit project, 2010$.

See the cost calculations in worksheet "Overall Sum—New Ref Review" of the Excel file, rows 12 and 13.

5.6 Air to Fuel Ratio Controller (AFRC) (NAFRCICENG)

The costs and cost effectiveness for applying AFRC to natural gas Lean Burn engines are obtained from the document *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines* (CARB 2001). Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-4 for AFRC, along with changes in assumptions for the current analysis.

Table 5-4. AFRC for Natural Gas Lean Burn Engines

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: not provided	Control efficiency: assumed 20%
Capital costs: provided for multiple models	None.
Annual Costs	
Equipment life: 10 yr	None.
Interest rate: 10%	Interest rate: 7%
Operating hours: 2000 hr/yr	None.
Emission rate, uncontrolled: 740 ppmv	Emission rate, uncontrolled: Assumed mid to upper end hp rating for each model.
Emission rate, controlled: 80% reduction	None.
Annualized equipment cost: provided for multiple model sizes	CRF: 0.1424
Annual O&M cost: assumed $0.	None.

AFRC are electronic engine controls that typically monitor engine parameters and atmospheric conditions to determine the correct air/fuel mixture for the operating condition, such as varying engine load or speed conditions, varying ambient conditions, or startup/shutdown conditions. (OTC 2012) (A discussion of individual technologies is provided in Appendix B of the original reference, CARB 2001, pp. B-1 to B-28). AFRC are known or demonstrated control techniques for lean burn engines. An 80 percent NOx emission reduction can be achieved by AFRC in combination with other combustion modifications, however a fuel consumption penalty of up to 3 percent can occur due to AFRC.

Capital were provided for multiple size ranges of engines. The capital costs ranged from $4,200 to $6,500 per engine.

No annual costs were provided in the document. No emissions reductions were provided in the document. Based on the cost analysis for other combustion technology controls in this document, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (this assumption ignores the fuel penalty issue). The total annual costs ranged from \$600 to \$930. Because no emission reductions were provided in the document, an estimate of emissions was made in the current analysis. In the current analysis, a hp rating based on the middle or upper end of each size range was assumed for estimating the uncontrolled NOx emissions. Uncontrolled NOx emissions were estimated based on an uncontrolled NOx concentration of 740 ppmv (this equates to approximately 9 g/bhp-hr), the operating hours were assumed to be 2000 hr/yr (similar to the operating hours for other control technology analyses provided in the document), and controlled emissions were estimated based on an assumption of 20 percent reduction. Uncontrolled NOx emissions ranged from 1.1 to 34 tpy for the models, and the NOx reductions ranged from 0.22 to 6.7 tpy for the models.

The current analysis shows a cost effectiveness of \$2,700/ton of NOx reduction to \$140/ton for 2000 hr/yr operation, and the average cost effectiveness across all the models is \$810/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited reference, 2001\$.

Based on the cost calculations for engines of varying hp, the following equations were developed for the capital cost and annual costs for AFRC on natural gas Lean Burn engines:

$$\text{Capital cost} = 1.3007 \text{ x (hp)} + 4354.5$$

$$\text{Annual cost} = 0.1852 \text{ x (hp)} + 619.99$$

The R^2 value for these equations is 0.87. These equations should be included in the CoST database file under a new equation type.

See the cost calculations in worksheet “AFRC (CARB)-2001” of the Excel file.

5.7 SCR (for 4 Stroke Natural Gas Engines) (NSCRICE4SNG)

The costs and cost effectiveness for applying SCR to natural gas engines are obtained from the document *Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion*

Engines—Phase 2) (SJVAPCD 2003). Information was provided on Capital costs, Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-5 for SCR for natural gas engines along with changes in assumptions for the current analysis. SCR is a known or demonstrated control technique for lean burn engines, although multiple references indicate that the feasibility of SCR application for lean burn engines is highly site-specific.

Table 5-5. SCR for Natural Gas Lean Burn Engines, 4-stroke.

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 90%	None.
Capital costs: based on RACT/BARCT Determination.	None.
Annual Costs	
Equipment life: 10 years	None.
Interest rate: 10%	Interest rate: 7%
Operating hours rate 1: 2190 hr/yr (equivalent to capacity factor of 0.25)	None.
Operating hours rate 2: 6570 hr/yr (equivalent to capacity factor of 0.75)	None.
Emission rate, uncontrolled: 740 ppmv NOx	None.
Emission rate, controlled: 65 ppmv NOx	None.
Annualized equipment cost: based on RACT/BARCT Determination.	None.
Annual O&M cost: based on RACT/BARCT Determination.	None.

The installed equipment capital cost ranged from $45,000 to $185,000 for 50 hp engines and 1500 hp engines, respectively. The total annual costs ranged from $27,000 for a 50 hp engine to $140,000 for a 1500 hp engine (these costs are very similar to the costs calculated in the original reference analysis; the only difference in annual costs is related to the CRF, i.e., changing the interest rate from 10 percent in the original reference analysis to 7 percent in the current analysis). NOx emissions are provided for two cases: a capacity factor of 0.25 (2190 hr/yr) and a capacity factor of 0.75 (6570 hr/yr). The uncontrolled NOx emissions ranged from 1.2 to 37 tpy for the lower capacity case, and the NOx reductions ranged from 1.1 to 33 tpy. For the higher capacity case, uncontrolled NOx emissions ranged from 3.7 to 110 tpy, and the NOx reductions achieved ranged from 3.3 to 100 tpy. The current analysis shows an average cost effectiveness of $8,700/ton of NOx reduction for 2190 hr/yr of operation, and $2,900/ton of NOx reduction for 6570 hr/yr operation (these cost effectiveness values are very similar to the costs shown in the original reference analysis).

Based on the cost calculations for engines of varying hp and annual capacity operating, the following linear equations were developed for the capital cost and annual costs for SCR on natural gas 4-stroke lean burn engines:

$$\text{Capital cost} = 107.1 \times (\text{hp}) + 27186$$

$$\text{Annual cost} = 83.64 \times (\text{hp}) + 14718$$

The R^2 values for these equations are 0.95 for capital cost and 0.98 for annual cost. These equations should be included in the CoST database file under a new equation type for linear equations.

The cost year is not provided in the reference; assumed the cost year is the date of the cost-basis document, 2001$.

See the cost calculations in worksheet "SCR NG (SJVAPCD)-2003" of the Excel file. [Other cost effectiveness values for SCR are available from the PA DEP that are higher than the cost effectiveness values shown for the SJVAPCD SCR analysis, and other analyses. See the summary of SCR costs in worksheet "Other SCR Cost Info" of the Excel file.]

5.8 SCR (for Diesel Engines) (NSCRICEDS)

The costs and cost effectiveness for applying SCR to diesel lean burn engines is provided in *Alternative Control Techniques Document: Stationary Diesel Engines* (EPA 2010). The assumptions for the original reference analysis are provided in Table 5-6 for SCR for diesel engines, along with changes in assumptions for the current analysis. SCR is a known or demonstrated control technique for lean burn, diesel engines.

Approximately 76 percent of the population of stationary diesel engines is less than 300 hp and the remaining 24 percent is greater than 300 hp. Applications for stationary engines under 300 hp include standby power generation, agriculture, and industrial applications, and less than 5 percent are used for continuous power generation. Applications for stationary engines greater than 300 hp are primarily power generation and are almost evenly divided between continuous duty and standby applications.

The cost analysis provided in the original reference includes an assumption that stationary diesel lean burn engines operate approximately 1000 hr/yr. This assumption is likely appropriate for the majority of those units that are less than 300 hp and for half of the diesel engines greater than 300 hp, i.e., approximately 87 percent of diesel lean burn engines (this ignores the “fewer than 5 percent” used for continuous power generation). For the remaining 13 percent of engines that are greater than 300 hp and used in continuous power generation applications, an assumption for longer operating hours, such as 8000 hr/yr, may be needed to estimate the cost effectiveness.

Table 5-6. SCR for Diesel Lean Burn Engines—Assumptions

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 90 %	None.
Equipment life: 15 year	None.
Interest rate: 7%	None.
Capital costs: $98/hp	None.
Annual Costs	
Operating hours: 1000 hr/yr	None.
Annual costs: $40/hp (based on 1000 hr/yr operation; already includes Capital Recovery)	None.

The original reference analysis provided a capital cost of $98/hp, and based on the mid-range hp rating for four model engines, the capital costs ranged from $7,300 to $98,000 for SCR. The original reference analysis provided an annual cost of $40/hp, and the annual costs ranged from $3,000 to $40,000 per year. Uncontrolled NOx emissions factors in the original reference were based on Tier 0 to Tier 3 values[1] and an assumption of 1000 hr/yr operation. Uncontrolled NOx emissions range from 0.25 to 9.2 tpy across the four models, and the NOx reductions ranged from 0.22 to 8.3 tpy.

The current analysis shows an average cost effectiveness of $9,300/ton of NOx reduction for 1000 hr/yr of operation (no weighting to the average based on engine age was applied). The cost effectiveness over the engine size range varied from $4,800/ton to $16,000/ton for diesel engines (and are very similar to the costs shown in the original reference analysis). It is

[1] Federal Standards, from the *Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling—Compression Ignition*. EPA Publication No. EPA420-P-04_009. April 2004.

important to note that the cost effectiveness is correlated to the manufacturing year of the diesel engine, i.e., the Tier limit for NOx emissions. Older engines manufactured prior to 1998 have the most lenient emissions limit while later model years have more stringent NOx emission limits (lower baseline emissions). The overall magnitude of emission reduction achieved by the SCR is lower for later model years as compared to earlier years, and therefore, the cost effectiveness values are higher for later model years.

[Note: This analysis shows emission reductions and cost effectiveness for existing and new diesel engines through approximately 2011, the last year for phase in of the Tiered emission values. The original reference provided information (circa 2005) on the age of the stationary engine population, with approximately 57 percent of engines at that time being manufactured prior to 1994 and approximately 42 percent manufactured after 1994 (note that the grouping of the age data does not align well with the Tier years, in that the age data shows breaks in 1994 and 2003 while the Tier ranges show breaks in 1996, 1998, 2002, 2003, etc.). As the diesel engine population continues to age and older engines are retired (i.e., those diesel engines subject to the Pre-1998 and the Tier 1 (1998 to 2003) or Tier 1 (1996 to 2001), etc. and are replaced with newer engines achieving lower NOx baseline emissions, the cost effectiveness for new engines would tend to be in the higher end shown for each model and would contribute to a somewhat higher average cost-effectiveness value. The average cost effectiveness will likely move toward the $13,000/ton to $16,000/ton of NOx reduction range.]

See the cost calculations in worksheet "SCR Diesel (EPA Dies ACT)-2010" of the Excel file.

5.9 Applicable SCCs for Lean Burn Engine Control Measures

Table 5-7 lists all of the ICE SCCs that are associated with one or more gas lean burn ICR control measures in the CMDB table called "Table 03_SCCs." These SCCs were identified with NOx emissions in an EPA query of the NEI for facilities in the Ozone Transport Group Assessment Region (i.e., 37 states that are partially or completely to the east of 100oW longitude). The control measures shown in the column headings in Table 5-7 are the ICE control measures that are currently in the CMDB. Each control measure that was determined to be applicable for a specific SCC is identified with an "N" in the cell, meaning the control measure is "new," i.e., not currently linked to this particular SCC, but we recommend adding this link in the database. In some cases, we recommend applying new links between existing control measures and existing SCCs. For example, some of the SCCs are for ICE that are fired with relatively uncommon fuels such as process gas, methanol, digester gas, or landfill gas. While we have not

Table 5-7. Potential Reciprocating Engine SCCs to Add to the CMDB and Applicable Control Measures

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Control Measures for the Reciprocating Engine SCC[d]										
					NAFRICGS	NAFRIICGS	NIRICGD	NIRICGS	NIRICOL	NIRRICOIL	NSCRICGD	NSCRICGS	NSCRICOL	NSCRRICOIL	NSNCRICGS
20200702	ICE	Ind	Process Gas	Reciprocating Engine	N	N		N				N			N
20200712	ICE	Ind	Process Gas	Reciprocating: Exhaust	N	N		N				N			N
20201602	ICE	Ind	Methanol	Reciprocating Engine			N				N				
20201607	ICE	Ind	Methanol	Reciprocating: Exhaust			N				N				
20201702	ICE	Ind	Gasoline	Reciprocating Engine			N				N				
20201707	ICE	Ind	Gasoline	Reciprocating: Exhaust			N				N				
20280001	ICE	Ind	Equipment Leaks	Equipment Leaks											
20282001	ICE	Ind	Wastewater, Aggregate	Process Area Drains											
20300702	ICE	C/I	Digester Gas	Reciprocating: POTW Digester Gas	N	N		N				N			N
20300707	ICE	C/I	Digester Gas	Reciprocating: Exhaust	N	N		N				N			N
20300802	ICE	C/I	Landfill Gas	Reciprocating	N	N		N				N			N
20400401	ICE	ET	Reciprocating Engine	Gasoline			N				N				
20400402	ICE	ET	Reciprocating Engine	Diesel/Kerosene			N		N	N	N		N	N	
20400404	ICE	ET	Reciprocating Engine	Process Gas	N	N		N							N
20400406	ICE	ET	Reciprocating Engine	Kerosene/Naphtha (Jet Fuel)			N				N				
20400409	ICE	ET	Reciprocating Engine	Liquified Petroleum Gas (LPG)			N				N				

[a]SCCs represent reciprocating engine activities that were identified with NOx emissions in the Ozone Transport Assessment Group Region analysis but are not associated with reciprocating engine control measures in the current CMDB.

[b]ICE means "Internal Combustion Engines."

[c]Ind means "Industrial," C/I means "Commercial/Institutional," and ET means "Engine Testing."

[d]The control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

located any analyses that determined the applicable controls and related costs for ICE fired with such fuels, similar control measures can be assigned to these SCCs. In order to conduct CoST modeling analyses for these ICE, the most representative available control measures could be assigned. For ICE that burn miscellaneous gaseous fuels, the most representative control measures are those for natural gas-fired ICE. Similarly, for ICE that burn miscellaneous liquid fuels such as methanol, gasoline, kerosene/diesel, and LPG, the most representative available control measures are those for gas- or diesel-fired ICE. Also, for ICE that burn liquid fuels such as diesel/kerosene, the most representative available control measures are those for gas-, diesel-, or oil-fired ICE.

Six new control measures have been added to the CMDB for lean burn engines under this review and these control measures are described in Sections 5.3 through 5.8 of this report. Table 5-8 lists those SCCs that should be associated with the newly added lean burn engine control measures. Each control measure that was determined to be applicable for a specific SCC is identified by a "Y," which means yes.

In Table 5-9, a number of recommendations were made to delete NOx control measure/SCC combinations from the CMDB. ICE SCCs for evaporative losses from fuel storage and delivery systems are incorrectly associated with NOx control measures in the current CMDB, and we recommend deleting these all NOx control measure/SCC records from the CMDB table called "Table 03_SCCs" because there should be no NOx emissions from the sources represented by these SCCs. In addition, multiple ICE control measures are misassigned to turbine SCCs and we recommend deleting these NOx control measure/SCC records. The reverse issue also exists where multiple turbine control measures are misassigned to ICE SCCs, and we recommend deleting these NOx control measure/SCC records, as well. These control measure/SCC combinations are identified in Table 5-9.

5.10 Pennsylvania General Permit 5 (GP-5) for Natural Gas Compression and/or Processing Facilities

Pennsylvania DEP recently released a general permit for Natural Gas Compression and/or Processing Facilities that includes limits on NOx emissions from ICE. NOx emission limits from this general permit, along with other NOx limits for Pennsylvania, are shown in Table 5-10. Typical emission rates and the cost-effectiveness values for applying certain control measures are shown for lean burn and rich burn engines in Table 5-11.

Table 5-8. Recommended New Control Measures to Associate With Lean Burn Reciprocating Engine SCCs in the CMDB

					Applicable Control Measures for the Lean Burn Reciprocating Engine SCC					
SCC[a]	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	NLECICENG	NLCICE2SNG	NLCICE2SLBNG	NAFRCICENG	NSCRICE4SNG	NSCRICEDS
20200102	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating						Y
20200107	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Exhaust						Y
20200252	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Lean Burn	Y	Y	Y	Y	Y	
20200254	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Lean Burn	Y	Y	Y	Y	Y	
20200255	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Clean Burn	Y	Y	Y	Y	Y	
20200256	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Clean Burn	Y	Y	Y	Y	Y	
20200401[b]	Internal Combustion Engines	Industrial	Large Bore Engine	Diesel			Y			
20200402[b]	Internal Combustion Engines	Industrial	Large Bore Engine	Dual Fuel (Oil/Gas)			Y			
20200403[b]	Internal Combustion Engines	Industrial	Large Bore Engine	Cogeneration: Dual Fuel			Y			

[a]SCCs represent reciprocating engine activities that were identified with NOx emissions in the recent Ozone Transport Region analysis but are not associated with reciprocating engine control measures in the current CMDB.

[b]The control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20200106	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Evap Losses	All NOx control measures
20200206	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Evap Losses	All NOx control measures
20200306	Internal Combustion Engines	Industrial	Gasoline	Reciprocating: Evap Losses	All NOx control measures
20200406	Internal Combustion Engines	Industrial	Large Bore Engine	Reciprocating: Evap Losses	All NOx control measures
20200506	Internal Combustion Engines	Industrial	Residual/Crude Oil	Reciprocating: Evap Losses	All NOx control measures
20200906	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Evap Losses	All NOx control measures
20201006	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Reciprocating: Evap Losses	All NOx control measures
20300106	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Evap Losses	All NOx control measures
20300206	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Evap Losses	All NOx control measures
20300306	Internal Combustion Engines	Commercial/Institutional	Gasoline	Reciprocating: Evap Losses	All NOx control measures
20301006	Internal Combustion Engines	Commercial/Institutional	Liquified Petroleum Gas (LPG)	Reciprocating: Evap Losses	All NOx control measures
20200108	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Turbine: Evap Losses	All NOx control measures
20200109	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Turbine: Exhaust	NNSCRRBIC
20200208	Internal Combustion Engines	Industrial	Natural Gas	Turbine: Evap Losses	All NOx control measures
20200209	Internal Combustion Engines	Industrial	Natural Gas	Turbine: Exhaust	NNSCRRBIC2
20200908	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Turbine: Evap Losses	All NOx control measures
20200909	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Turbine: Exhaust	NNSCRRBGD

(continued)

Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB (continued)

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20201008	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Evap Losses	All NOx control measures
20201009	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Exhaust	NNSCRRBGD
20201011	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine	NNSCRRBGD
20201013	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Cogeneration	NNSCRRBGD
20300108	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Turbine: Evap Losses	All NOx control measures
20300109	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Turbine: Exhaust	NNSCRRBIC
20300208	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Turbine: Evap Losses	All NOx control measures
20300209	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Turbine: Exhaust	NNSCRRBIC2
20200105	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Crankcase Blowby	NNSCRWGTOL, NWTINGTOL
20200107	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Exhaust	NSCRWGTOL, NWTINGTOL
20200205	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Crankcase Blowby	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200207	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Exhaust	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200252	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Lean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200253	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Rich Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200254	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Lean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200255	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Clean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG

(continued)

Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB (continued)

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20200256	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Clean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200905	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Crankcase Blowby	NSCRWGTJF, NWTINGTJF
20200907	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Exhaust	NSCRWGTJF, NWTINGTJF
20300105	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Crankcase Blowby	NNSCRWGTOL, NWTINGTOL
20300107	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Exhaust	NSCRWGTOL, NWTINGTOL
20300205	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Crankcase Blowby	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20300207	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Exhaust	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG

Table 5-10. NOx Control Requirements for RICE in Pennsylvania

State	Source Category Covered	NOx Control Level	Reference
Pennsylvania	153 ton NOx/season	≥2400 hp: 3 g/bhp-hr (220 ppm)	IEPA 2007
Pennsylvania (proposed values) [Assume proposal was 2011Mar26]	General Permit—Natural Gas Production and Processing Facility, SI, ICE	Existing LB or RB, 100 to 1500 hp: 2 g/bhp-hr New, Reconfigured, LB ≤100 hp: 2 g/bhp-hr New, Reconfigured, LB 100 to 637 hp: 1 g/bhp-hr New, Reconfigured, LB >637 hp: 0.5 g/bhp-hr	OTC 2012
Pennsylvania (amended 2013Feb02)	Natural Gas Compression and Processing, NG, SI, ICE, includes facilities with actual or potential emissions <100 tpy NOx, and <25 tpy NOx in 5 counties.	New, Reconfigured LB or RB, ≤100 hp: 2 g/bhp-hr New, Reconfigured LB, 100 to 500 hp: 1 g/bhp-hr New, Reconfigured LB, >500 hp: 0.5 g/bhp-hr New, Reconfigured RB, 100 to 500 hp: 0.25 g/bhp-hr New, Reconfigured RB, >500 hp: 0.2 g/bhp-hr	PA DEP 2013
Pennsylvania	Interstate Pollution Transport Reduction, Emission of NOx from Stationary ICE	LB, >2400 hp: 3.0 g/bhp-hr RICE, RB, >2400 hp: 1.5 g/bhp-hr	DE 2012

Table 5-11. Characteristics of NOx Emissions and Controls for RICE

Engine Type and Size	Uncontrolled Emissions	Emissions	Cost Effectiveness for NOx Reductions	Reference
Lean burn				
LB >500 hp	NA	SCR, stack test, 0.22 to 0.50 g/bhp-hr	SCR: $71,000 to $60,000/ton (for 500 to 4000 hp)	PA DEP 2013, p. 22
LB 100 to 500 hp	1 to 16.4 g/bhp-hr	NA	SCR: >$42,000/ton	PA DEP 2013, p. 20
LB <100 hp	2 g/bhp-hr	2 g/bhp-hr	SCR: >$48,000/ton	PA DEP 2013, p. 17
Rich burn				
RB >500 hp	13 to 16 g/bhp-hr	NSCR: stack test, 0.02 to 0.14 g/bhp-hr	NA	PA DEP 2013, p. 28, 29
RB 100 to 500 hp	13 to 16.4 g/bhp-hr.	NA	NSCR: $177/ton	PA DEP 2013, p. 25, 26
RB <100 hp	11.41 to 21.08 g/bhp-hr	NSCR: <2 g/bhp-hr, at least 90% reduction	NSCR: <$650/ton for 100 hp NSCR: <$1200/ton for 50 hp	PA DEP 2013, p. 17

APPENDIX A
AMMONIA REFORMERS

Copies of database tables showing all records for ammonia reformer controls, highlighting revisions.

Table A-1. CMDB Table 06 References (New)

Data Source	Description
AR-1	Indian Nations Council of Governments (INCOG), 2008: Indian Nations Council of Governments (INCOG), "Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O3 Flex Program," March 6, 2008. Downloaded from http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf

Table A-2. CMDB Table 01 Summary

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Low NOx Burner; Ammonia—NG-Fired Reformers	NLNBUFRNG	N0561	NOx	Low NOx Burner	Ammonia—NG-Fired Reformers	ptnonipm	Known	10	204|205	*2013*	*AR-1 |186*		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia—NG-Fired Reformers	NLNBFFRNG	N0562	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia—NG-Fired Reformers	ptnonipm	Known	10		2006	72|172|175|179|186		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia—Oil-Fired Reformers	NLNBFFROL	N0572	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia—Oil-Fired Reformers	ptnonipm	Known	10		2006	72		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with oil-fired reformers (SCC 30100307). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia Prod; Feedstock Desulfurization	NLNBFAPFD	N0622	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia Prod; Feedstock Desulfurization	ptnonipm	Known	10		2006	72|172|175|179|185		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton per OSD) feedstock desulfurization processes in ammonia products operations (SCC 30100305) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: It is assumed that the superheated steam needed to regenerate the activated carbon bed used in the desulfurization process is the NOx source. LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Oxygen Trim and Water Injection; Ammonia—NG-Fired Reformers	NOTWIFRNG	N0563	NOx	Oxygen Trim and Water Injection	Ammonia—NG-Fired Reformers	ptnonipm	Known	10		2006	72|172|175|179|184|185		Application: This control is the use of OT + WI to reduce NOx emissions This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. This control is also applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Selective Catalytic Reduction; Ammonia—NG-Fired Reformers	NSCRFRNG	N0564	NOx	Selective Catalytic Reduction	Ammonia—NG-Fired Reformers	ptnonipm	Known	20	139	2006	72|167|175|179|224|225|226		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to natural-gas fired reformers involved in the production of ammonia (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.
Selective Catalytic Reduction; Ammonia—Oil-Fired Reformers	NSCRFROL	N0573	NOx	Selective Catalytic Reduction	Ammonia—Oil-Fired Reformers	ptnonipm	Known	20	139	2006	72		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to natural-gas fired reformers involved in the production of ammonia (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Selective Non-Catalytic Reduction—Ammonia; NG-Fired Reformers	NSNCRFRNG	N0565	NOx	Selective Non-Catalytic Reduction	Ammonia—NG-Fired Reformers	ptnonipm	Known	20	107	2006	72|172|175|179|185		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to small (<1 ton NOx per OSD) ammonia production natural gas fired reformers (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.
Low NOx Burner; Ammonia—Oil-Fired Reformers	NLNBUFROL	N0571	NOx	Low NOx Burner	Ammonia—Oil-Fired Reformers	ptnonipm	Known	10	204|205	2006	72		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with oil-fired reformers (SCC 30100307). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Selective Non-Catalytic Reduction—Ammonia; Oil-Fired Reformers	NSNCRFROL	N0574	NOx	Selective Non-Catalytic Reduction	Ammonia—Oil-Fired Reformers	ptnonipm	Known	20	107	2006	72		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to ammonia production natural gas fired reformers (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Low NOx Burner; Ammonia Production; Other Not Classified	NLNBUAONC		NOx	Low NOx Burner	Ammonia Production—Other Not Classified	ptnonipm	Known	10	204|205	2013	AR-1|186		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002)
Low NOx Burner and Flue Gas Recirculation; Ammonia Production; Other Not Classified	NLNBFAONC		NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia Production—Other Not Classified	ptnonipm	Known	10		2013	72|172|175|179|186		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Selective Non-Catalytic Reduction—Ammonia; Ammonia Production; Other Not Classified	NSNCRAONC		NOx	Selective Non-Catalytic Reduction	Ammonia Production—Other Not Classified	ptnonipm	Known	20	107	2013	72|172|175|179|185		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.
Oxygen Trim and Water Injection; Ammonia Production; Other Not Classified	NOTWIAONC		NOx	Oxygen Trim and Water Injection	Ammonia Production—Other Not Classified	ptnonipm	Known	10		2013	72|172|175|179|184|185		Application: This control is the use of OT + WI to reduce NOx emissions This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Selective Catalytic Reduction; Ammonia Production; Other Not Classified	NSCRAONC		NOx	Selective Catalytic Reduction	Ammonia Production—Other Not Classified	ptnonipm	Known	20	139	2013	72|167|175|179|224|225|226		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.

Table A-3. CMDB Table 02 Efficiencies

cmabbreviation	Pollutant	Locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	Details
NLNBFAPFD	NOx				0	0	365	60	1990	2560	100	100	cpton	0.1424		5.9	2470	Applied to small source types
NLNBFAPFD	NOx				0	365		60	1990	590	100	100	cpton	0.1424		7.5	280	Applied to large source types
NLNBFFRNG	NOx				0	0	365	60	1990	2560	100	100	cpton	0.1424		5.9	2470	Applied to small source types
NLNBFFRNG	NOx				0	365		60	1990	590	100	100	cpton	0.1424		7.5	280	Applied to large source types
NLNBFFROL	NOx				0	0	365	60	1990	1120	100	100	cpton	0.1424		5.9	1080	Applied to small source types
NLNBFFROL	NOx				0	365		60	1990	390	100	100	cpton	0.1424		7.5	190	Applied to large source types
NLNBUFROL	NOx				0	0	365	50	1990	400	100	100	cpton	0.1424		5.5		Applied to small source types
NLNBUFROL	NOx				0	365		50	1990	430	100	100	cpton	0.1424		5.5		Applied to large source types
NOTWIFRNG	NOx				0	0	365	65	1990	680	100	100	cpton	0.1424		2.9		Applied to small source types
NOTWIFRNG	NOx				0	365		65	1990	320	100	100	cpton	0.1424		2.9		Applied to large source types
NSCRFRNG	NOx				0	0	365	90	1999	2366	100	100	cpton	0.0944		10		Applied to small source types
NSCRFRNG	NOx				0	365		90	1999	2366	100	100	cpton	0.0944		9.6		Applied to large source types
NSCRFROL	NOx				0	0	365	80	1990	1480	100	100	cpton	0.0944		10	1910	Applied to small source types
NSCRFROL	NOx				0	365		80	1990	810	100	100	cpton	0.0944		9.6	940	Applied to large source types
NSNCRFRNG	NOx				0	0	365	50	1990	3870	100	100	cpton	0.0944		9.4	2900	Applied to small source types
NSNCRFRNG	NOx				0	365		50	1990	1570	100	100	cpton	0.0944		8.2	840	Applied to large source types
NSNCRFROL	NOx				0	0	365	50	1990	2580	100	100	cpton	0.0944		9.4	1940	Applied to small source types
NSNCRFROL	NOx				0	365		50	1990	1050	100	100	cpton	0.0944		8.2	560	Applied to large source types
NLNBUFRNG	NOx				0	0	365	50	1990	820	100	100	cpton	0.1424		5.5		Applied to small source types; *no new information was available for small sources during 2013 update*
NLNBUFRNG	NOx				0	365		50	*2008*	*800*	100	100	cpton	0.1424		*5.9*		Applied to large source types; *equipment life of 10 years and 7% interest*

APPENDIX B
COMBUSTION TURBINES

Copies of the database tables for showing all records for Combustion Turbines NOx controls are provided. Changes are highlighted in red font.

– Table B-1. CMDB Table 01_Summary

– Table B-2. CMDB Table 02_Efficiencies

– Table B-3. CMDB Table 04_Equations

– Table B-4. Additional CMDB Table 06_References

Table B-1. CMDB Table 01_Summary

cmname	cmabbreviation	pechanmeascode	majorpoll	controltechnology	sourcegroup	sector	class	equiplife	neidevicecode	datereviewed	datasource	months
Dry Low NOx Combustion; Gas Turbines—Natural Gas	NDLNCGTNG	N0243	NOx	Dry Low NOx Combustion	Gas Turbines—Natural Gas	ptnonipm	Known	15	204|205	2013	72|172|175|179|223|CT-2|CT-6	
SCR + Dry Low NOx Combustion; Gas Turbines—Natural Gas	NSCRDGTNG	N0244	NOx	SCR + DLN Combustion	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|179|223|224|CT-2|CT-3|CT-4|CT-6|CT-8	
Selective Catalytic Reduction and Steam Injecti; Gas Turbines—Natural Gas	NSCRSGTNG	N0245	NOx	Selective Catalytic Reduction and Steam Injection	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|179|223|224|CT-2|CT-3	
Selective Catalytic Reduction and Water Injecti; Gas Turbines—Jet Fuel	NSCRWGTJF	N0502	NOx	Selective Catalytic Reduction and Water Injection	Gas Turbines—Jet Fuel	ptnonipm	Known	15		2013	72|172|175|179|223|CT-2|CT-7	
Selective Catalytic Reduction and Water Injecti; Gas Turbines—Natural Gas	NSCRWGTNG	N0246	NOx	Selective Catalytic Reduction and Water Injection	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|179|223|224|CT-2|CT-3|CT-8	
Selective Catalytic Reduction and Water Injecti; Gas Turbines—Oil	NSCRWGTOL	N0232	NOx	Selective Catalytic Reduction and Water Injection	Gas Turbines—Oil	ptnonipm	Known	15		2013	72|172|175|179|223|224|CT-2|CT-7	
Steam Injection; Gas Turbines—Natural Gas	NSTINGTNG	N0242	NOx	Steam Injection	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|184|223|CT-2	
Water Injection; Gas Turbines—Jet Fuel	NWTINGTJF	N0501	NOx	Water Injection	Gas Turbines—Jet Fuel	ptnonipm	Known	15		2013	72|172|175|184|223|CT-2	
Water Injection; Gas Turbines—Natural Gas	NWTINGTNG	N0241	NOx	Water Injection	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|184|223|CT-2	
Water Injection; Gas Turbines—Oil	NWTINGTOL	N0231	NOx	Water Injection	Gas Turbines—Oil	ptnonipm	Known	15		2013	72|172|175|184|223|CT-2	
Catalytic Combustion; Gas Turbine—Natural Gas	NCATCGTNG	N/A	NOx	Catalytic Combustion	Gas Turbines—Natural Gas	ptnonipm	Emerging	15		2013	CT-1|CT-2	
EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas	NEMXDGTNG	N/A	NOx	EMx and Dry Low NOx Combustion	Gas Turbines—Natural Gas	ptnonipm	Emerging	15		2013	CT-1|CT-2|CT-3|CT-4|CT-5	
EMx and Water Injection; Gas Turbines—Natural Gas	NEMXWGTNG	N/A	NOx	EMx and Water Injection	Gas Turbines—Natural Gas	ptnonipm	Emerging	15		2013	CT-1|CT-3	

*For ease in reading this table, the Description field is included on separate pages.

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NDLNCGTNG	Application: This control is the use of dry low NOx combustion (DLN) technology to reduce NOx emissions. DLN combustion reduces the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to large (83.3 MW to 161 MW) natural gas fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
NSCRDGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRSGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year.

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRSGTNG (cont.)	Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTJF	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRWGTJF (cont.)	Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTOL	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to oil-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002).

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRWGTOL (cont.)	Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSTINGTNG	Application: This control is the use of steam injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Steam is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The steam can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTJF	Application: This control is the use of water injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTNG	Application: This control is the use of water injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTOL	Application: This control is the use of water injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) oil-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NCATCGTNG	Application: This control is the use of catalytic combustion to reduce NOx emissions. Catalytic combustors reduce the amount of NOx created by oxidizing fuel at lower temperatures (and without a flame) than in conventional combustors. Catalytic combustion uses a catalytic bed to oxidize a lean air fuel mixture within a combustor instead of burning with a flame. The fuel and air mixture oxidizes at lower temperatures than in a conventional combustor, producing less NOx. Currently installed only on a few 1.4 MW combustion turbines, and commercially available for turbines rated up to 10 MW (CT-1).
NEMXDGTNG	Application: This control is the use of EMx in combination with dry low NOx combustion. EMx is a post-combustion catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of NOx as well as CO, VOC, and optionally SOx. A coated catalyst oxidizes NO to NO2, CO to CO2, and VOC to CO2 and water. The NO2 is then absorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. A proprietary regeneration gas is periodically passed through the catalyst to desorb the NO2 from the catalyst and reduce it to elemental nitrogen (N2). EMx has been successfully demonstrated on several small combustion turbine projects up to 45 MW. The manufacturer has claimed that EMx can be effectively scaled up to larger turbines (CT-1). Cost estimates for DLN combustion in 2008 dollars are not available. Thus, the total system cost in this analysis in 2008 dollars was developed from 1999 cost estimates for DLN combustion that were escalated to 2008 dollars and added to the available 2008 estimate for the EMx system.
NEMXWGTNG	Application: This control is the use of EMx in combination with water injection. Cost estimates for water injection in 2008 dollars are not available. Thus, the total system cost in this analysis in 2008 dollars was developed from 1999 cost estimates for water injection that were escalated to 2008 dollars and added to the available 2008 estimate for the EMx system.

Table B-2. CMDB Table 02_Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NWTINGTNG	NOx				0	0	365	72	1999	1790	100	100	cpton	0.1098		3.1		Applied to small source types (<34.4 MW), uncontrolled emissions <365 tpy
NWTINGTNG	NOx				0	365		72	1999	1000	100	100	cpton	0.1098		2.4		Applied to small source types (<34.4 MW), uncontrolled emissions >365 tpy
NWTINGTNG	NOx				0	365		72	1999	730	100	100	cpton	0.1098		1.6		Applied to large source types
NSCRWGTNG	NOx				0	0	365	94	1999	2790	100	100	cpton	0.1098		3	5840	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.
NSCRWGTNG	NOx				0	365		94	1999	1370	100	100	cpton	0.1098		2.9	3130	Applied to small source types (3 to 26 MW), uncontrolled emissions >365 tpy.
NSCRWGTNG	NOx				0	365		94	1999	1070	100	100	cpton	0.1098		1.5	1690	Applied to large source types (~80 to 160 MW)
NSCRWGTNG	NOx				0	365		98	2008	1960	100	100	cpton	0.1098		2.5	3170	Applied to large source types (~50 to 180 MW), 1999 costs for WI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units. 1999 WI capital and indirect annual costs were escalated to 2008 dollars using ratio of 2008 to 1999 CEP cost indexes, direct annual costs for WI were assumed to be the same in 2008 as in 1999, and resulting 2008 costs were added to the 2008 SCR costs from ref CT-3.
NEMXWGTNG	NOx				0	365		99	2008	2960	100	100	cpton	0.1098		2.9	7120	Applied to large source types (50 to 180 MW); WI costs estimated using the same procedure as for NSCRWGTNG applied to large sources.
NSTINGTNG	NOx				0	0	365	80	1999	1690	100	100	cpton	0.1098		3.5		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSTINGTNG	NOx				0	365		80	1999	820	100	100	cpton	0.1098		3.5		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSTINGTNG	NOx				0	365		80	1999	500	100	100	cpton	0.1098		3.0		Applied to large source types (~80 to 160 MW), 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSCRSGTNG	NOx				0	0	365	95	1999	2570	100	100	cpton	0.1098		3.3	5550	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.

(continued)

Table B-2. CMDB Table 02_Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NSCRSGTNG	NOx				0	365		95	1999	1380	100	100	cpton	0.1098		3.1	2870	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRSGTNG	NOx				0	365		95	1999	570	100	100	cpton	0.1098		2.7	1810	Applied to large source types (~80 to 160 MW)
NSCRGYNG	NOx				0	365		95	2008	1420	100	100	cpton	0.1098		3.9	3170	Applied to large source types (50 to 180 MW)
NDLNCGTNG	NOx				0	0	365	84	1999	300	100	100	cpton	0.1098		5	~~540~~	Applied to small source types
NDLNCGTNG	NOx				0	365		84	1999	130	100	100	cpton	0.1098		7.4	~~140~~	Applied to large source types
NSCRDGTNG	NOx				0	0	365	94	1999	1800	100	100	cpton	0.1098		2.9	11900	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy.
NSCRDGTNG	NOx				0	365		94	1999	990	100	100	cpton	0.1098		3.6	6320	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRDGTNG	NOx				0	365		94	1999	390	100	100	cpton	0.1098		4.2	3340	Applied to large source types (~160 MW)
NSCRDGTNG	NOx				0	365			2007								18900	Applied to small source types (up to 40 MW, uncontrolled emissions <365 tpy)
NSCRDGTNG	NOx				0		365		2007								7510	Applied to small source types (up to 40 MW, uncontrolled emissions >365 tpy)
NSCRDGTNG	NOx				0	365		94	2008	1040	100	100	cpton	0.1098		4.6	5560	Applied to large source types (~50 to 180 MW), 1999 costs for DLN were estimated based on data in ref CT-2. Escalated these costs to 2008 dollars using ratio of 2008 to 1999 CEP cost indexes and added to the 2008 SCR costs from ref CT-3.
NEMXDGTNG	NOx						365		1999	2860							14940	Applied to small source types (<26 MW), uncontrolled emissions <365 tpy
NEMXDGTNG	NOx					365			1999	1720							10270	Applied to small source types (<26 MW), uncontrolled emissions >365 tpy
NEMXDGTNG	NOx					365			1999	840							6600	Applied to large source types (170 MW), uncontrolled emissions >365 tpy
NEMXDGTNG	NOx				0		365											Applied to small source types
NEMXDGTNG	NOx				0	365		99	2008	2040	100	100	cpton	0.1098		4.1	12370	Applied to large source types (50 to 180 MW); DLN costs estimated in 1999 dollars were escalated to 2008 dollars using the CEPCI, except parts and repair costs were assumed to be the same in 2008 as in 1999.
NCATCGTNG	NOx				0		365	98	1999	920	100	100	cpton	0.1098		1.7	4760	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.
NCATCGTNG	NOx				0		365	98	1999	670	100	100	cpton	0.1098		1.2	2580	Applied to small source types (3 to 26 MW), uncontrolled emissions >365 tpy.
NCATCGTNG	NOx				0	365		98	1999	370	100	100	cpton	0.1098		0.7	2200	Applied to large source types (~170 MW)
NWTINGTOL	NOx				0	0	365	68	1999	1630	100	100	cpton	0.1098		3.0		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.

Table B-2. CMDB Table 02_Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NWTINGTOL	NOx				0	365		68	1999	960	100	100	cpton	0.1098		1.8		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.
NWTINGTOL	NOx				0	365		68	1999	650	100	100	cpton	0.1098		1.6		Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.
NSCRWGTOL	NOx				0	0	365	90	1990	3190	100	100	cpton	0.1098		2.9	7620	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy.
NSCRWGTOL	NOx				0	365		90	1990	1320	100	100	cpton	0.1098		2.3	2450	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRWGTOL	NOx				0	365		97	2004	1560	100	100	cpton	0.1098		2.3	4790	Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, 1999 costs for WI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units. Escalated these costs to 2004 dollars using ratio of 2004 to 1999 CEP cost indexes and added to the 2004 SCR costs from ref CT-7. Control efficiency based on data from analysis for one unit (ref CT-7).
NWTINGTJF	NOx				0	0	365	68	1999	1630	100	100	cpton	0.1098		3.0		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, costs assumed to be the same as for oil-fired turbines.
NWTINGTJF	NOx				0	365		68	1999	960	100	100	cpton	0.1098		1.8		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, costs assumed to be the same as for oil-fired turbines.
NWTINGTJF	NOx				0	365		68	1999	650	100	100	cpton	0.1098		1.6		Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, costs and control efficiency assumed to be the same as for oil-fired turbines.
NSCRWGTJF	NOx				0	0	365	90	1990	3190	100	100	cpton	0.1098		2.9	7620	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, costs assumed to be same as for oil-fired turbines.
NSCRWGTJF	NOx				0	365		90	1990	1320	100	100	cpton	0.1098		2.3	2450	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, costs assumed to be same as for oil-fired turbines.
NSCRWGTJF	NOx				0	365		97	2004	1560	100	100	cpton	0.1098		2.3	4790	Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, costs and control efficiency assumed to be same as for oil-fired turbines).

Table B-3. CMDB Table 04_Equations[a]

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NWTINGTNG	Type 2	NOx	1999	27665	0.69	3700.2	0.95	27665	0.69	3700.2	0.95		
NSCRWGTNG	Type 2	NOx	1999	62962	0.66	8590	0.87	37193	0.63	12065	0.64		
NSCRWGTNG	Type 2	NOx	2007					210883	0.46				
NSCRWGTNG	Type “L”	NOx	2007							1893.8	185570		
NSCRWGTNG	Type 2	NOx	2008	34533	0.85	7236	0.94	10323	0.96	3106	0.94		
NEMXWGTNG	Type 2	NOx	2008	200894	0.68	19215	0.86	160409	0.67	20174	0.78		
NSTINGTNG	Type 2	NOx	1999	43092	0.66	7282.3	0.76	43092	0.66	7282.3	0.76		
NSCRSGTNG	Type 2	NOx	1999	72169	0.66	17551	0.72	37193	0.63	12065	0.64		
NSCRSGTNG	Type 2	NOx	2008	46492	0.82	9434.1	0.86	10323	0.96	3106	0.94		
NDLNCGTNG	Type 2	NOx	1999			676.37	0.96			676.37	0.96		
NDLNCGTNG	Type “L”	NOx	1999	2860.6	25427			2860.6	25427				
NSCRDGTNG	Type 2	NOx	1999	24854	0.79	12725	0.69	37193	0.63	12065	0.64		
NSCRDGTNG	Type 2	NOx	2007	187647	0.54			210883	0.46				
NSCRDGTNG	Type “L”	NOx	2007			2782	167494			1893.8	185570		
NSCRDGTNG	Type 2	NOx	2008	14785	0.97	5250.8	0.9	10323	0.96	3106.1	0.94		
NEMXDGTNG	Type 2	NOx	1999	58237	0.78	15004	0.78	65163	0.72	13702	0.76		
NEMXDGTNG	Type 2	NOx	2008	129611	0.74	23051	0.78	160409	0.67	20174	0.78		
NCATCGTNG	Type 2	NOx	1999	20668	0.57	4254.2	0.82						
NCATCGTNG	Type “L”	NOx	1999					N/A	N/A	743.2	54105		
NWTINGTOL	Type 2	NOx	1999	42533	0.6	6776.7	0.8	42533	0.6	6776.7	0.8		
NSCRWGTOL	Type 2	NOx	1990	94337	0.63	25914	0.7						
NSCRWGTOL	Type “L”	NOx	1999					4868.5	349694	1546.1	139203		

[a]Type “L” is a linear equation; variables are the slope and intercept. No incremental TCI for NCATCGTNG relative to DLN because the capital costs for catalytic combustion are lower than the capital costs for DLN for all but the smallest turbines. The underlying data for 2008 costs for SCR and EMx are for large turbines (50 MW to 180 MW). The underlying data for 2007 costs are for 1 MW to 40 MW turbines.

Table B-4. Additional CMDB Table 06 References

Data Source	Description
CT-1	Bay Area Air Quality Management District, 2010. Preliminary Determination of Compliance. Marsh Landing Generating Station. March 2010. Available at: http://www.energy.ca.gov/sitingcases/marshlanding/documents/other/2010-03-24_Bay_Area_AQMD_PDOC.pdf
CT-2	Onsite Sycom Energy Corporation, 1999. "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines." Prepared for U.S. Department of Energy. Environmental Programs Chicago Operations Office. November 5, 1999. Available at: https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/gas_turbines_nox_cost_analysis.pdf
CT-3	EmeraChem Power, 2008. Attachment in email from Jeff Valmus, EmeraChem Power, to Weyman Lee, BAAQMD. Request for EMx Cost Information. September 8, 2008. Available at: http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/18404/Footnotes/EMx%20BACT%20economic%20analysis%20final09072008.ashx
CT-4	CH2MHill, 2002. Walnut Energy Center Application for Certification." Prepared for California Energy Commission. November 2002. Available at: www.energy.ca.gov/sitingcases/turlock/documents/applicant_files/volume_2/App_08.01E_Eval_Control.pdf.
CT-5	CARB, 2004. California Environmental Protection Agency. Air Resources Board. Report to the Legislature. Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts. Stationary Source Division. May 2004. Available at: http://www.arb.ca.gov/research/apr/reports/l2069.pdf
CT-6	Resource Dynamics Corporation, 2001. "Assessment of Distributed Generation Technology Applications." Prepared for Maine Public Utilities Commission. February 2001. Available at: http://www.distributed-generation.com/Library/Maine.pdf
CT-7	Florida Municipal Power Agency, 2004. Chapters 3 and 4 of PSD BACT analysis for Stock Island facility in Key West, Florida. Available at http://www.dep.state.fl.us/air/emission/construction/stockisland/BasisofBACT.pdf and http://www.dep.state.fl.us/air/emission/construction/stockisland/NOxBACT.pdf
CT-8	Energy and Environmental Analysis (An ICF International Company), 2008. Technology Characterization: Gas Turbines. Prepared for Environmental Protection Agency Climate Protection Partnership Division. December 2008. Available at: http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

APPENDIX C
GLASS MANUFACTURING

Copies of database tables showing all records for glass manufacturing controls, highlighting revisions.

Table C-1. CMDB Table 01 Summary

cmname	cmabbreviation	pechanmeascode	major poll	controltechnology	sourcegroup	Sector	Class	equiplife	neideviceсode	datereviewed	datasource	Months	Description
Cullet Preheat; Glass Manufacturing—Container	NCLPTGMCN	N0302	NOx	Cullet Preheat	Glass Manufacturing—Container	ptnonipm	Emerging	10		2013	72|175|182|GM-1		
Cullet Preheat; Glass Manufacturing—Pressed	NCUPHGMPD	N0322	NOx	Cullet Preheat	Glass Manufacturing—Pressed	ptnonipm	Emerging	10		2013	72|175|182|GM-1		
OXY-Firing; Glass Manufacturing—General	NDOXYFGMG	N/A	NOx	OXY-Firing	Glass Manufacturing—General	ptnonipm	Emerging	10			167		
Electric Boost; Glass Manufacturing—General	NELBOGMGN	N0301	NOx	Electric Boost	Glass Manufacturing—Container	ptnonipm	Known	10		2013	GM-1		
Electric Boost; Glass Manufacturing—Container	NELBOGMCN	N0301	NOx	Electric Boost	Glass Manufacturing—Container	ptnonipm	Known	10		2006	72|175|182		
Electric Boost; Glass Manufacturing—Flat	NELBOGMFT	N0311	NOx	Electric Boost	Glass Manufacturing—Flat	ptnonipm	Known	10		2006	72|175|182		
Electric Boost; Glass Manufacturing—Pressed	NELBOGMPD	N0321	NOx	Electric Boost	Glass Manufacturing—Pressed	ptnonipm	Known	10		2006	72|175|182		
Low NOx Burner; Glass Manufacturing—Container	NLNBUGMCN	N0303	NOx	Low NOx Burner	Glass Manufacturing—Container	ptnonipm	Known	10	204|205	2013	72|175|179|182|GM-2		
Low NOx Burner; Glass Manufacturing—Flat	NLNBUGMFT	N0312	NOx	Low NOx Burner	Glass Manufacturing—Flat	ptnonipm	Known	10	204|205	2013	72|175|179|182|GM-2		
Low NOx Burner; Glass Manufacturing—Pressed	NLNBUGMPD	N0323	NOx	Low NOx Burner	Glass Manufacturing—Pressed	ptnonipm	Known	10	204|205	2006	175|179|182		
OXY-Firing; Glass Manufacturing—General	NOXYFGMGN	N0306	NOx	OXY-Firing	Glass Manufacturing—Container	ptnonipm	Known	10		2013	GM-1		
OXY-Firing; Glass Manufacturing—Container	NOXYFGMCN	N0306	NOx	OXY-Firing	Glass Manufacturing—Container	ptnonipm	Known	10		2006	72		
OXY-Firing; Glass Manufacturing—Flat	NOXYFGMFT	N0315	NOx	OXY-Firing	Glass Manufacturing—Flat	ptnonipm	Known	10		2006	72		
OXY-Firing; Glass Manufacturing—Pressed	NOXYFGMPD	N0326	NOx	OXY-Firing	Glass Manufacturing—Pressed	ptnonipm	Known	10		2006	72		
Selective Catalytic Reduction; Glass Manufacturing—Container	NSCRGMCN	N03403	NOx	Selective Catalytic Reduction	Glass Manufacturing—Container	ptnonipm	Known	10	139	2013	72|172|175|179|182|224|GM-2		
Selective Catalytic Reduction; Glass Manufacturing—Flat	NSCRGMFT	N0314	NOx	Selective Catalytic Reduction	Glass Manufacturing—Flat	ptnonipm	Known	10	139	2013	72|172|175|179|182|186|224|GM-2		
Selective Catalytic Reduction; Glass Manufacturing—Pressed	NSCRGMPD	N0325	NOx	Selective Catalytic Reduction	Glass Manufacturing—Pressed	ptnonipm	Known	10	139	2006	72|172|175|179|182|186|224		
Catalytic Ceramic Filter; Glass Manufacturing—Flat	CATCFGMFT		NOx	Catalytic Ceramic Filter	Glass Manufacturing—Flat	ptnonipm	Known	20		2013	GM-3		

Table C-1. CMDB Table 01 Summary—Description Field

cmabbreviation	description
NCLPTGMCN	Application: This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to container glass manufacturing operations classified under 305010402.
NCUPHGMPD	Application: This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to pressed glass manufacturing operations classified under 305010404.
NDOXYFGMG	Application: This control is the use of OXY-firing in glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NELBOGMGN	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to general glass manufacturing operations classified under SCC 30501401.
NELBOGMCN	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to container glass manufacturing operations classified under SCC 30501402. Discussion: The 250 tons per day plant is assumed to be representative of container glass plants (Pechan, 1998).
NELBOGMFT	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to flat glass manufacturing operations classified under SCC 30501403. Discussion: The 500 tons per day plant is assumed to be representative of flat glass plants (Pechan, 1998).
NELBOGMPD	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to pressed glass manufacturing operations classified under SCC 30501403. Discussion: The 50 tons per day plant is assumed to be representative of pressed glass plants (Pechan, 1998).
NLNBUGMCN	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to container glass manufacturing operations classified under 305010402 with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The 250 tons per day plant is assumed to be representative of container glass plants (Pechan, 1998). LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
NLNBUGMFT	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to flat glass manufacturing operations classified under 305010404 with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The 500 tons per day plant is assumed to be representative of flat glass plants (Pechan, 1998). LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).

(continued)

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NLNBUGMPD	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amo
NOXYFGMGN	Application: This control is the use of OXY-firing in flat glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” This control applies to general manufacturing operations. This control applies to general glass manufacturing operations classified under SCC 30501401. Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMCN	Application: This control is the use of OXY-firing in container glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMFT	Application: This control is the use of OXY-firing in flat glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” This control applies to flat-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMPD	Application: This control is the use of OXY-firing in pressed glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.

(continued)

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NSCRGMCN	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to glass-container manufacturing processes, classified under SCC 30501402 and uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRGMFT	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to large(>1 ton NOx per OSD) flat-glass manufacturing operations (SCC 30501403) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).

(continued)

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NSCRGMPD	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to pressed-glass manufacturing operations, classified under SCC 30101404 and uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
CATCFGMFT	Application: Filter tubes have nanobits of proprietary catalyst are embedded throughout the filter walls. The system can achieve excellent NOx removal using liquid ammonia that is injected upstream of the filters, reacting with NOx at the catalyst to form nitrogen gas and water vapor. This control applies to general glass manufacturing operations classified under SCC 30501403

Table C-2.   CMDB Table 02 Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existing measure abbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equation type	caprecfactor	discountrate	capannratio	incrementalcpt	details
NCLPTGMCN	NOx				0	365	0	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to large source types
NCLPTGMCN	NOx				0	0	365	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to small source types
NCUPHGMPD	NOx				0	365		5	2002	5000	100	100	cpton	0.1424		4.5		Applied to large source types
NCUPHGMPD	NOx				0	0	365	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to small source types
NELBOGMCN	NOx				0	365		10	1990	7150	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMCN	NOx				0	0	365	10	1990	7150	100	100	cpton	0.1424		0		Applied to small source types
NELBOGMFT	NOx				0	365		10	1990	2320	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMFT	NOx				0	0	365	10	1990	2320	100	100	cpton	0.1424		0		Applied to small source types
NELBOGMPD	NOx				0	365		10	1990	8760	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMPD	NOx				0	0	365	10	1990	2320	100	100	cpton	0.1424		0	8760	Applied to small source types
NELBOGMGN					0	365	0	30	2002	7100	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMGN					0	0	365	30	2002	7100	100	100	cpton	0.1424		0		Applied to small source types
NLNBUGMCN	NOx				0	365		40	2007	1072	100	100	cpton	0.14		4.3	1690	Applied to large source types
NLNBUGMCN	NOx				0	0	365	40	2007	1365	100	100	cpton	0.14		4.2	1690	Applied to small source types
NLNBUGMFT	NOx				0	0	365	40	2007	574	100	100	cpton	0.14		4.2		Applied to small source types
NLNBUGMFT	NOx				0	365		40	2007	447	100	100	cpton	0.14		4.3		Applied to large source types
NLNBUGMPD	NOx				0	365		40	1990	1500	100	100	cpton	0.1424		2.2		Applied to large source types
NLNBUGMPD	NOx				0	0	365	40	1990	1500	100	100	cpton	0.1424		2.2		Applied to small source types
NOxYFGMCN	NOx				0	0	365	85	1990	4590	100	100	cpton	0.1424		2.7		Applied to small source types
NOxYFGMCN	NOx				0	365		85	1990	4590	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMFT	NOx				0	365		85	1990	1900	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMFT	NOx				0	0	365	85	1990	1900	100	100	cpton	0.1424		2.7		Applied to small source types
NDOXYFGMG	NOx				0			85	1999	4277	100	100	cpton					
NOxYFGMPD	NOx				0	0	365	85	1990	3900	100	100	cpton	0.1424		2.7		Applied to small source types
NOxYFGMPD	NOx				0	365		85	1990	3900	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMGN						365	0	85	2002	2353	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMGN						0	365	85	2002	2353	100	100	cpton	0.1424		2.7		Applied to small source types
NSCRGMCN	NOx				0	365	0	75	2007	1684	100	100	cpton	0.1424		4.2		Applied to large source types
NSCRGMCN	NOx				0	0	365	75	2007	2169	100	100	cpton	0.1424		4.5		Applied to small source types
NSCRGMFT	NOx				0	365	0	75	2007	855	100	100	cpton	0.1424		3.7	710	Applied to large source types
NSCRGMFT	NOx				0	0	365	75	2007	957	100	100	cpton	0.1424		3.4		Applied to small source types

(continued)

Table C-2. CMDB Table 02 Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existing measure abbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equation type	caprecfactor	discountrate	capannratio	incrementalcpt	details
NSCRGMPD	NOx				0	365		75	1990	2530	100	100	cpton	0.1424		1.3		Applied to large source types
NSCRGMPD	NOx				0	0	365	75	1990	2530	100	100	cpton	0.1424		1.3		Applied to small source types
CATCFGMFT	NOx				0	365	0	95	2013	997	100	100	cpton	0.05		4.6		Applied to large source types
CATCFGMFT	NOx				0	0	365	95	2013	1045	100	100	cpton	0.05		4.6		Applied to small source types

Table C-3. CMDB Table 06 References (New)

Data Source	Description
GM-1	Oxygen Enriched Air Staging a Cost-effective Method For Reducing NOx Emissions. Industrial Technologies. April 2002. Available at: http://www1.eere.energy.gov/manufacturing/resources/glass/pdfs/airstaging.pdf
GM-2	Best Available Techniques (BAT) Reference Document for the Manufacture of Glass. European Commission 2013. Available at: http://eippcb.jrc.ec.europa.eu/reference/BREF/GLS_Adopted_03_2012.pdf
GM-3	Confidential Vendor Quote

Table C-4. CMDB Table 04_Equations[a]

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NLNBUGMCN	Type 2	NOx	2008	30,930	0.45	9,377	0.40						
NLNBUGMFT	Type “L”	NOx	2008	527	664,557	132	150,105						
NSCRGMCN	Type 2	NOx	2008	79,415	0.51								
NSCRGMCN	Type “L”	NOx	2008			643	135,302						
NSCRGMFT	Type “L”	NOx	2008	3,681	1,000,000	842	424,930						

[a]Type “L” is a linear equation; variables are the slope and intercept.

APPENDIX D
LEAN BURN ENGINES

Copies of the database tables for showing all records for Lean Burn Engine NOx controls are provided:

– Table D-01_Summary

– Table D-02_Efficiencies

– Table D-03_SCCs

– Table D-04_Equations

– Table D-06_References

Table D-01_Summary

cmname	cmabbreviation	pechanmeascode	majorpoll	controltechnology	sourcegroup	sector	class	equiplife	neidevicecode	datereviewed	datasource	months	description
Low Emission Combustion; Lean Burn ICE—NG	NLECICENG		NOx	Low Emission Combustion	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD3		Low Emission Combustion includes Precombustion chamber head and related equipment on a Lean Burn engine.
Layered Combustion; Lean Burn ICE 2 stroke—NG	NLCICE2SNG		NOx	Layered Combustion	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD1		Layered combustion—2 stroke, Lean Burn, NG (Air Supply; Fuel Supply; Ignition; Electronic Controls; Engine Monitoring). Evaluation for 3 most representative made/models of 2 stroke LB compressor engines. All retrofit combustion-related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).
Layered Combustion; Lean Burn ICE 2 stroke Large Bore—NG	NLCICE2SLBNG		NOx	Layered Combustion	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD1		Layered combustion—for Large Bore, 2 stroke, Lean Burn, Slow Speed (High Pressure Fuel Injection achieves 90% reduction; Turbocharging achieves 75% reduction; Precombustion chambers achieves 90% reduction; Cylinder Head Modifications). All retrofit combustion-related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).
Air to Fuel Ratio Controller; Lean Burn ICE—NG	NAFRCICENG		NOx	Air to Fuel Ratio Controller	Lean Burn ICE—NG	PTNONIPM	Known	10		12/5/2012	ABCD3		
Selective Catalytic Reduction; Lean Burn ICE 4 Stroke—NG	NSCRICE4SNG		NOx	Selective Catalytic Reduction	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD1| ABCD2| ABCD3		SCR can be used on Lean Burn, NG engines. Assumed SCR can meet NOx emissions of 0.89 g/bh-hr. This is a Known technology, however there is indication that applicability is engine/unit specific.
Selective Catalytic Reduction; ICE—Diesel	NSCRICEDS		NOx	Selective Catalytic Reduction	ICE—Diesel	PTNONIPM	Known	7		9/15/2013	ABCD4		SCR can be used on Diesel engines.

Table D-02_Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equation type	caprecfactor	discount rate	capannratio	incrementalcpt	details
NLECICENG	NOx	NA	NA	NA	NA	0	365	80	2001	1,000	100	100	cpton	0.1424	7	7.025	NA	
NLCICE2SNG	NOx	NA	NA	NA	NA	0	365	97	2009	4,900	100	100	cpton	0.1424	7	7.024	NA	
NLCICE2SLBNG	NOx	NA	NA	NA	NA	365	0	97	2010	1,500	100	100	cpton	0.1424	7	7.024	NA	Apply to large source types. Assumed Interest Rate of 7 percent (not provided in documentation) to calculate annual costs.
NLCICE2SLBNG	NOx	NA	NA	NA	NA	0	365	97	2010	38,000	100	100	cpton	0.1424	7	7.024	NA	Apply to small source types.
NAFRCICENG	NOx	NA	NA	NA	NA	0	365	80	2001	200	100	100	cpton	0.1424	7	7.023	NA	
NSCRICE4SNG	NOx	NA	NA	NA	NA	0	365	96	2001	2,900	100	100	cpton	0.1424	7	1.401	NA	
NSCRICEDS	NOx	NA	NA	NA	NA	0	365	90	2005	9,300	100	100	cpton	0.1098	7	2.45	NA	

Table D-03_SCCs

cmabbreviation	Source Classification Code	Status
NLECICENG	20200252	
NLECICENG	20200254	
NLECICENG	20200255	
NLECICENG	20200256	
NLCICE2SNG	20200252	
NLCICE2SNG	20200254	
NLCICE2SNG	20200255	
NLCICE2SNG	20200256	
NLCICE2SLBNG	20200252	
NLCICE2SLBNG	20200254	
NLCICE2SLBNG	20200255	
NLCICE2SLBNG	20200256	
NLCICE2SLBNG	20200401	
NLCICE2SLBNG	20200402	
NLCICE2SLBNG	20200403	
NAFRCICENG	20200252	
NAFRCICENG	20200254	
NAFRCICENG	20200255	
NAFRCICENG	20200256	
NSCRICE4SNG	20200252	
NSCRICE4SNG	20200254	
NSCRICE4SNG	20200255	
NSCRICE4SNG	20200256	
NSCRICEDS	20200102	
NSCRICEDS	20200107	

Table D-04_Equations

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NSCRICE4SNG	linear capital and annual	NOx	2001	107.1	27186	83.64	14718						
NLECICENG	capital and annual	NOx	2001	16019	0.0016	2280.8	0.0016						
NAFRCICENG	linear capital and annual	NOx	2001	1.0337	4354.5	0.1852	619.99						

Table D-06 References

Data Source	Description
ABCD1	OTC 2012. Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final. October 17, 2012.
ABCD2	SJVAPCD 2003. RULE 4702—Internal Combustion Engines—Phase 2. Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2). San Joaquin Valley Air Pollution Control District. July 17, 2003. www.arb.ca.gov/pm/pmmeasures/ceffect/rules/sjvapcd_4702.pdf
ABCD3	CARB 2001. Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.
ABCD4	EPA 2010. Alternative Control Techniques Document: Stationary Diesel Engines. March 5, 2010.

APPENDIX E

NOTES PROVIDED HERE TO EPA QUESTIONS ON LEAN BURN RICE

EPA Question 1: What is the applicability of SCR to RICE, especially Lean Burn?

Notes for Question 1

In addition to the two documents cited in Section 5 of the report with costs for selective catalytic reduction (SCR) for Lean Burn (LB) engines, there are several other references that indicate SCR is feasible for LB engines and several that provide input on technical issues related to SCR use for LB engines. In summary, from the references reviewed, SCR seems to be technically feasible in most instances for LB engines, however, SCR application may not be feasible in all cases due to technical issues at individual sites and individual engines. In addition, SCR costs are higher relative to other NOx control techniques for LB engines. See more detailed discussion below.

SCR can be applied to LB engines, achieving greater than 90 percent NOx reductions (Table 4 on p. 6 provides a slightly different value, greater than 95 percent). The costs [assumed this referred to capital costs] ranged from $50/hp to $125/hp. No annual operating costs were provided. In discussions on p. 8 regarding "catalysts on IC engines" in general (including NSCR, SCR, oxidation, and Lean-NOx), it is noted that "Thousands of stationary IC engine catalyst applications have been effectively used for stationary IC engine gaseous emission control for five years or more. Some installations, however, do experience performance loss over time," however the text goes on to explain remedies for catalyst poisoning issues. Costs [capital] for SCR, LB ranged from $50 to $125/hp (no cost year provided). (MECA 1997)

The literature suggests that SCR is technically feasible for LB engines but there are problems that make SCR installation questionable. Two stroke (2S) LB engines are sensitive to changes in exhaust pressure, which could be problematic for retrofit of SCR on existing engines, but can be alleviated with proper design and sizing of airflow and exhaust components. This reference cited a presentation that indicated the following issues with SCR: applying SCR to pipeline engines is not feasible because the exhaust temperatures (T) are below the operating window for SCR or where SCR effectiveness is reduced; SCR installations are at unmanned facilities; and SCR has not been demonstrated for variable loads. However, the OTC 2012 reference responded to each of these issues, stating that there are several manufacturers and suppliers that offer SCR systems that indicate their catalysts are capable of effectively operating over a wide range of exhaust gas T; modern software based controls and SCADA communication technologies allow operation from a remote location; and SCR can function properly over a broad range of loads given catalysts that are effective over wide T ranges, modern controls regulate fuel and air flows to ensure combustion O_2 and T are at expected levels and to regulate reagent flow. A study conducted for retrofitting existing pipeline engines indicates that SCR is a high cost alternative to combustion improvements, primarily due to the high cost of ongoing reagent consumption. (p. 25-26) (There is a similar discussion for SCR for four stroke (4S) LB on p. 39-40; cited presentation at Gas Machinery Conference in October 2011.) (OTC 2012)

Shell indicated they have installed SCR on diesel engines (LB) that they utilize in drilling rig operations. Shell indicated that have been able to achieve greater than 90 percent reduction in NOx emissions while encountering minimal operational issues (see p. 10). (OTC 2012)

The OTC 2012 document indicated that MECA has noted there have been limited examples to date of SCR retrofit on 2S LB engines as demonstration test programs, but the results of these programs have not been published (see p. 27). It appears that SCR for NOx does not appear to be technically infeasible generically but that individual 2S LB engine characteristics and installations may be greatly problematic or not cost effective, although this site-specific issue is not altogether different than other emission reduction technologies (see p.27, 40). (OTC 2012)

The OTC 2012 document indicated that MECA has stated the commercial use of SCR systems for LB stationary engines have been in place since the mid-1980’s in Europe and since the early 1990s in the US. One MECA member company has installed over 400 SCR systems worldwide for stationary engines with varying fuel combinations, including dozens of NG compressor engines in the US. These 4S LB engines with urea-SCR achieve >90% NOx reduction (see p.40). (OTC 2012)

EF&EE announced in November 2010 that is received an order from Clean Air Power Inc. for 6 SCR systems, to be installed on large LB NG compressor engines at gas storage sites in TX and MS (see p.40). (OTC 2012)

Clean Air Power cited: 4 SCRs supplied at Pine Prairie Energy Center, Louisiana; 1 SCR supplied at EXTERRAN/TRESPALACIOS, Texas; and 4 SCRs supplied to EXTERRAN/LEAF River, Mississippi (see p.41). (OTC 2012)

A PowerPoint slide presentation from a MARAMA workshop discusses the use of SCR for RICE and LB. Johnson Mathey (JM) included SCR as a feasible control for LB engines in a presentation at a May 2011 MARAMA Workshop. (The SCR systems included Urea and Ethanol as reagents.) SCR operating temperatures range from 700 to 900°F for internal combustion (IC) engines and achieved 90 percent NOx reductions. The budgetary costs [assumed this referred to capital costs] ranged from $150/ hp for a 500 hp unit (approximately $75,000) to $42/hp for a 3000 hp unit (approximately $126,000) (cost year not provided). No annual operating costs were provided. JM cited 4 LB engine installations of SCR on gas compressors at 2 locations, including Loudon Compressor Station in Clarksburg, WV and Lodi Compressor/Storage in Kirby Hills, CA. (Chu 2011) These engines are listed in the following table:

SCR for Lean Burn Engines—Johnson Mathey presentation at 2007 MARAMA Workshop

Engine Model	Engine hp	NOx, g/bhp-hr	NOx Reduction, %
CAT G3516	1,340	1.5	90%
CAT G3608	2,370	0.7	90%
CAT G3612	3,550	0.7	90%
CAT G3616	4,735	0.7	90%

References

(MECA 1997). *Emission Control Technology for Stationary Internal Combustion Engines: Status Report*. Manufacturers of Emission Controls Association (MECA). July 1997.

(Chu 2011). *NOx Control for Stationary Gas Engines*. W. Chu, Johnson Mathey. Presented at Advances in Air Pollution Control Technology, MARAMA Workshop. May 19, 2011.

(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final.* October 17, 2012.

EPA Question 2: What are credible estimates of the percentage of RICE NOx Emissions that are lean burn versus rich burn when RICE emissions are unspecified?

Notes for Question 2

There does not seem to be much information on NOx emission totals for LB and rich burn (RB) engines. A few references attempted to provide information on the numbers or populations of LB and RB engines. Several of the references highlighted surveys of engine populations and summary information from various engine databases. These data in general tend to point to a large LB engine population, however most of the references noted that RB engines are typically not captured or covered in surveys, databases, or by permits because the RB engines tend to be smaller in size. In general, larger engines tend to be LB and smaller engines tend to be RB. The ERLE 2009 study noted that approximately 73% of the 5,600 engines/horsepower capacity covered in their study of NG pipeline systems are LB, and approximately 6% are RB (the balance is not known). In the KSU 2011 database, approximately 66% of the 4,729 engines used in E&P at major sources are LB and 34% are RB. In addition, the EDF 2008 document cited a 2007 survey conducted for DFW NAA and AA that attempted to identify those engines that did not meet reporting requirement thresholds and were therefore not included in the TCEQ inventory. This reference, which included small engines, indicated that for smaller engines <500 hp, approximately 96% are RB and 4% are LB. The reference also indicated that for larger engines >500 hp, there is approximately a 50-50 split of LB and RB engines and of horsepower capacity. The ETCG 2013 reference also highlights engines in the Barnett Shale region. Data from the TCEQ Barnett Shale Special Inventory (Phase I) survey indicated that the majority of engines in the Barnett Shale are RB (84%). For those engines <240 hp, 95% are RB and 5% are LB, however, in looking at those engines >240 hp, 59% are LB and 41% are RB. More details for each of these references are provided in the discussion that follows.

Note also that the emissions rate in g/bhp-hr for LB engines tend to be higher, and the emissions rate for RB engines tends to be lower. (See the tables under Question 4 of this appendix for relative emission rate values for LB and RB engines in various states and local districts.)

A summary of the information available from various references is provided below.

The CARB 2001 reference indicated that LB engines tend to be larger in size, and smaller engines tend to be RB (p.B-4). (CARB 2001)

EPA received comments from the Interstate Natural Gas Association of America (INGAA) on the 2002 proposed rule, where EPA indicated that 156 of 168 large engines listed in the NOx SIP Call Inventory that have SIC codes associated with the NG transmission industry are LB engines (with the exception that the other 12 engines are no longer in service, are owned by a company not included in the industry database, or are duplicates). INGAA recommended that EPA assume all large NG stationary engines in the inventory are LB. (EPA 2003).

One prominent use of large Reciprocating Internal Combustion Engines (RICE) is to drive NG pipeline compressor stations; almost all engines affected by the NOx SIP Call Phase 2 rule in IL (except for 3 engines) are used to compress NG at NG pipeline stations. (IEPA 2007)

A 2009 ERLE study cited in this reference indicated there are 5,600 engines on the NG pipeline systems with a collective rating of 9,150,000 hp. That study further indicated that approximately 80 percent of the rated output was low speed 2S, low speed 4S integral engines and diesel medium speed engines converted to spark ignition (SI). Of these 80 percent of engines, 78 percent were 2S LB, 14 percent were 4S LB, and 8 percent were 4S RB. (On a rated horsepower basis, 80 percent was 2S LB, 15 percent was 4S LB, and 5 percent 4S RB) (p. 16). [On an overall basis, compared to the full 9,150,000 hp collective rating, 2S LB would be roughly 62%, 4S LB would be roughly 11%, and 4S RB would be roughly 6% of the overall rating/engines. So 73% would be LB, 6% would be RB, and the balance is not known.] (OTC 2012)

Engine Type	No. Engines, %	Horsepower, %
2S LB	78	80
4S LB	14	15
4S RB	8	5

The DE 2012 document cited a 2003 Pipeline Research Council International (PRCI) document that identified 5,686 engines: 71% are LB and 29% are RB (based on dropping the turbine numbers in the table below) (p.19). (DE 2012) [These data may be repeated in OTC 2012, as it looks fairly similar to the 2009 ERLE study data cited above from OTC 2012.]

2003 Pipeline Research Council International Data (PRCI)

Unit Type	U.S. Total Units (%)	Avg hp
2S LB	2,955 (44%)	2,113
4S LB	1,059 (16%)	1,844
RB	1,672 (25%)	589
Turbine	1,016 (15%)	6,121

Energy Information Agency (EIA) data cited in the OTC 2012 reference indicated there were 1201 NG mainline compressor stations in the U.S. in 2006, with combined rating of 16,800,000 hp. Between 2007 and 2010, the Federal Energy Regulation Commission (FERC) approved new compressor stations or upgrades to existing compressor facilities that were expected to add 2,600,000 hp (p. 16). (OTC 2012)

The Kansas State University (KSU) 2011 document included a database on 4,729 engines used in Exploration and Production (E&P) at major sources. LB engines accounted for 66 percent of engines (17 percent are 2S and 49 percent are 4S), and RB engines accounted for 34 percent. LB outnumbers RB among engines included in the database; because many engines rating less than 100 hp are not included, and because the majority of the smaller units are 4S RB, RB are actually underrepresented in the database. A listing of the engines (manufacturer and model), air to fuel (A/F) ratio type, cycle, and horsepower are included in Appendix I of the KSU 2011 document. The database was not meant to collect every single engine in use but rather to provide a frequency distribution of engines. The data was pulled from multiple sources, including the State of Wyoming Engine Inventory Database, EPA ICCR Database, GTI/PRCI Engine and Turbine Database, and Database of Colorado and New Mexico Engines (from Universal Compression). The engine database likely includes only permitted engines, and lower-hp engines are underrepresented in the database. (pp. 5-7) (KSU 2011)

The EDF 2008 reference indicated most engines in Barnett Shale area of Texas are 100 to 500 hp but some large engines of 1000+ hp are also used. (EDF 2008)

The EDF 2008 reference indicated that the TCEQ Point Source Emissions Inventory (PSEI) does not include a substantial fraction of compressor engine emissions. Most of the missing engines in the DFW NAA were units with emissions below the reporting thresholds, but the combined emissions from large numbers of these engines can be substantial (pp. 13-14). The 2007 DFW Engine survey indicated there were approximately 680,000 hp of installed engine capacity in DFW NAA not previously reported to the TCEQ PSEI (p. 14). The report also estimated that there is approximately 132,000 hp of engines in Attainment Area (AA) counties within the Barnett Shale that don’t report to PSEI (non-PSEI) (p. 14). The LB and RB engine data from the 2007 DFW Engine Survey for the DFW NAA is provided in the table below. In this survey, there seem to be fairly even numbers of LB (51%) and RB (49%) engines in the >500 hp category, and there seems to be fairly even horsepower capacity for the LB and RB engines. For smaller engines that are <500 hp, there are significantly more RB engines (736 engines, or 96%) than LB engines (27 engines, or 4%). In addition, for the smaller engines <500 hp, the horsepower capacity for RB represents 15% and for LB is <1%. (EDF 2008)

Installed Engine Capacity in 2007 DFW Engine Survey by Engine Type and Size, in DFW NAA (EDF 2008)

Engine Type	Engine Size, hp	Number of Engines	Percent of Engines, %	Typical Size, hp	Installed Capacity, hp	Percent of Installed Capacity, %
RB	<50	12	1.03%	50	585	0.086%
RB	50–500	724	62%	140	101,000	15%
RB	>500	200	17%	1,400	280,000	41%
LB	<500	27	2.3%	185	4,940	0.72%
LB	>500	206	18%	1,425	294,000	44%

The EDF 2008 reference looked at all of the compressor engines in the Barnett Shale region, including both the engines located within the DFW NAA and the engines in the DFW AA (including those larger engines that report to the PSEI and those non-PSEI engines). New TCEQ rules became effective in 2009 to reduce NOx from the subset of engines located in the DFW NAA that typically are not reported to the PSEI (due to their small size) for major sources (p. 25). Engines that are located outside the DFW NAA are not subject to the 2009 rule. As shown in the table below, a 50% reduction of emissions from 2007 to 2009 was estimated in DFW NAA, taking into account the growth, regulation affect, and NSCR installations. For AA engines, emissions will increase from 2007 to 2009 due to growth and the fact that no regulation applies (these engines not subject to 2009 engine regulation) (p. 19). (EDF 2008)

NOx Emissions from Compressor Engines in Barnett Shale of Texas (EDF 2008)

Area	2007 NOx Emissions, tpd	2009 NOx Emissions, tpd
DFW NAA engines	32	16
AA engines	20	31
Barnett Shale engines, total	52	47

The reference then looked at emission reductions for extending the 2009 rule to all engines in the Barnett Shale (including those in the AA). By extending the 2009 engine rule, NOx emissions from AA engines would drop by approximately 6.5 tpd (p.25) (this approach reduces emissions from a large number of engines, in particular RB engines between 50 to 500 hp). (EDF 2008)

The ETCG 2013 reference indicated that analysis of test reports at the TCEQ Tyler office showed 68 compressor engines: 9 engines (13%) <240 hp and 59 engines (87%) ≥240 hp (and 69% of all engines ≥500 hp) (p.11). (A graph showing the distribution of the hp for all 68 engines is shown on p.12 of the reference document.) (ETCG 2013)

The ETCG 2013 reference discussed TCEQ Barnett Shale Special Inventory (Phase I) survey data. The table below is a summary of the engine horsepower distribution. (A graph showing the distribution of NG engines in the Barnett Shale region is shown in Figure 5-1 on p. 21 of the reference document.) The majority of engines in the Barnett Shale are RB and are <240 hp, see the two tables below. This data set shows that smaller hp engines are predominantly RB, with 2,089 engines <240 hp are RB (95%) and 104 engines (5%) are LB. For engines >240 hp, 327 engines (59%) are LB and 230 engines (41%) are RB.

2009 Equipment Inventory of Stationary NG Engines by Horsepower for Barnett Shale Region. (ETCG 2013)

Engine Size	Total Engines	Percent of Total Engines	Engine Type, RB or LB	Number of Engines	Percent of Each Size Category
0 to 50 hp	317	12%	RB	302	95%
			LB	15	4.7%
50 to 240 hp	1,876	68%	RB	1,787	95%
			LB	89	4.7%
>240 hp	557	20%	RB	230	41%
			LB	327	59%

Barnett Shale Special Inventory Phase I Equipment Survey Data on Stationary Gas-Fired Engines for 2009. (ETCG 2013)

Engine counts		
<240 hp	**≥240 hp**	**Total**
RB and LB		
2,193	557	2,750
RB only		
2,089	230	2,319
LB only		
104	327	431

The CO DPHE reference indicates that large NG RICE represent 16% of the statewide point source NOx emissions (16,199 tpy of 101,818 tpy) and 73% of the ICE NOx emissions (16,199 tpy of 22,210 tpy) (p. 1). (CO DPHE)

Example Emissions Estimates: It is difficult to draw conclusions for the emissions from LB versus RB from the data provided. However, some assumptions could be made to help draw conclusions for the defined scenario. If assume that the total capacity between LB and RB in the ERLE study is more representative of the total reporting population than the 50–50 split in the EDF study; assume that operating hours are similarly distributed for both LB and RB; and if the EFs tend to be higher for LB than for RB engines, then it is likely that 90% plus of the total emissions are from LB.

References

(CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

(IEPA 2007). Technical Support Document for Controlling NOx Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines. AQPSTR 07-01. Illinois Environmental Protection Agency, Air Quality Planning Section, Division of Air Pollution Control, Bureau of Air. March 19, 2007.

(EPA 2003). Stationary Reciprocating Internal Combustion Engines: Technical Support Document for NOx SIP Call. U.S. Environmental Protection Agency. D. Grano and B. Neuffer. October 2003.

(EDF 2008). *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost Effective Improvements.* Conducted by Department of Environmental and Civil Engineering, Southern Methodist University, for Environmental Defense Fund. Peer-Review Draft. September 30, 2008.

(KSU 2011). *Final Report: Cost-Effective Reciprocating Engine Emissions Controls and Monitoring for E&P Field and Gathering Engines*. K. Hohn and S. Nuss-Warren, Kansas State University. November 2011.

(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final.* October 17, 2012. [This document focuses on Offshore Gulf of Mexico, Rocky Mountains, Southwest, and Mid-Continent areas.]

(ETCG 2013). *Gas Compressor Engine Study for Northeast Texas, for East Texas Council of Governments*. Prepared by ENVIRON International Corporation, for East Texas Council of Governments. June 2013.

(CO DPHE). *Reciprocating Internal Combustion Engine (RICE) Source Category, Reasonable Progress Evaluation for RICE Source Category*. Colorado Department of Public Health and Environment—Air Pollution Control Division.

EPA Question 3: What is the effect of NOx SIP call controls on RICE in NOx SIP call states? That is, what percent reduction and types of controls have gone into place in states affected by the NOx SIP call?

Notes for Question 3

The applicability, reduction achieved, and cost for RICE NOx controls are often engine specific and highly variable. (DE 2012) (OTC 2012)

Common NOx control techniques are provided in the table below, along with NOx emission reductions achievable. (References from other areas outside of the NOx SIP call states also provided details on controls and emissions reductions achieved by these controls and are included in the table.)

Effectiveness of Combustion Control Technologies and Add-On Controls

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
2 Stroke, LB				
Improved combustion air flow, Turbocharger	(p. 18, 31): up to 75%	Up to 90%; 0.5 to 2 g/bhp-hr (increases fuel economy; may increase CO) (p. 9)	—	—
Retard ignition timing	(p. 54): diesel, 10% (reduces engine efficiency; increases PM)	Up to 10% (increase fuel economy; may increase CO) (p. 9)	(p. B-7,8): 15 to 30% (increases fuel consumption; increases VOC, HAP)	20% (pp. 5-7); $310 to $2,000/ton (p. 8)
Improved air fuel mixing, High Pressure Fuel Injection	(p. 18, 31): up to 90%	—	—	—
Advanced In-cylinder mixing	—	30 to 70% (p. 11)	—	—
Precombustion chamber (PCC) ignition system	(p. 19, 31-32): up to 90%	1 g/bhp-hr (p. 10)	—	—
Micro Precombustion chamber (MPCC), hybrid of High energy Ignition system and PCC	—	2 to 4 g/bhp-hr (p. 10)	—	—
Screw-in PCC	—	1 g/bhp-hr (p. 10)	—	—
Autobalance cylinders	(p. 23): not provided	—	—	—

(continued)

Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
2 Stroke, LB (cont.)				
Air to Fuel Ratio Controller (AFRC)	(p. 19, 32): not provided	Not provided; use in combo with Increased air flow, or postcombustion Catalyst; a few thousand $ for small engine to $30K for larger engines (p. 12).	(p. B-8): not provided (fuel consumption penalty of 3%; may increase CO, VOC)	5 to 30% (pp. 5-7); $320 to $8,300/ton (p. 7)
Combustion modifications, Layered Combustion controls	(p. 25): 60 to 90%; range of 0.5 to 3 g/bhp-hr	—	—	—
4 stroke, LB				
EGR and NSCR	(p. 32): (emissions lower than SCR)[a]	—	—	—
Combustion modifications, Layered Combustion controls	(p. 38): 90%; range of 0.5 to 2 g/bhp-hr	—	—	—
Engines (general) or LB				
High energy ignition system (HEIS)	(p. 18, 31, 44): 10%	2.5 to 3 g/bhp-hr (pp. 9-10)	(p. B-12): 200 ppm NOx	—
Low emission combustion (LEC)/precombustion chamber retrofit (PCC) [also applicable to RB]	—	—	(p. B-10): 80% (may increase VOC, CO)	—
Turbocharging/ supercharging, and Aftercooling	(p. 18): Up to 75%	—	(p. B-13): 3 to 35% for Aftercooling (may reduce VOC, CO; increases engine efficiency, power rating)	—
EGR	(p. 55): diesel, >40% (loss of fuel efficiency; loss of engine output)	Still under development for NG engines; not cost effective at this time (p. 11).	(p. B-14): 30% (reduces engine peak power; reduces fuel efficiency by 2 to 12%)	—
Ignition system improvement	—	—	(p. B-11-2): not provided (may increase VOC, CO)	—

(continued)

Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
Engines (general) or LB (cont.)				
Homogeneous charge compression ignition (HCCI), combines best features of SI and CI engines	—	Still in R&D phase, no reduction or cost info available (reduces PM; high efficiency) (p. 11-12).	—	—
Fuel switching, Hydrogen/NG blended fuel	—	40 to 50% (p. 12) Still under development, no cost info available; use of H_2 blend removes need for PCC; H_2 fuel would need to be available in the field.	—	—
Selective Catalytic Reduction (SCR)	(p. 19, 32, 55): 50 to 95% (reduces THC, CO)	80 to 90% (can release NH3) (p. 13)	(p. B-23): >80%	80 to 90% (pp. 5-7); $430 to $4,900/ton (p. 9)
Lean-NOx catalysts	(p. 55): diesel, 10 to 50%	Up to 80% (reduces CO, HC by 60%; reduces fuel economy by 3%) (p. 14)	(p. B-24): diesel, 25 to 50% (increases fuel consumption; may increase VOC, PM)	—
NOxTech	—	—	(p. B-25): 80 to 90%; (decreases CO, VOC, PM by 80%; fuel penalty 5 to 10%)	—
Lean NOx traps	(p. 55): diesel, up to 90%	—	—	—
NOx Adsorber Technology (SCONOx)	—	—	(p. B-27): >90% on diesel engine <100 hp; [2 ppmv on NG turbine]	—
Selective noncatalytic reduction (SNCR) [also applicable to RB]	—	—	—	50 to 95% (pp. 5-7)

(continued)

Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
Engines (general) or LB (cont.)				
Fuel switching, methanol	—	—	(p. B-16): 30% for conversion from NG to methanol (can generate formaldehyde emissions)	—
Hybrid system, modification of dual bed NSCR system	—	—	(p. B-22): 3 to 4 ppm NOx	—
Use of electric motors in place of combustion engines	—	—	(p. B-27): >60%	60 to 100% (pp. 5-7); $100 to $4,700/ton [not include full costs] (p. 9)
RB				
Nonselective catalytic reduction (NSCR) plus AFRC	(p. 45, 49-51): 90 to 99% (reduces CO, VOC)	>90%, < 1 g/bhp-hr (reduces CO, HC) (p. 13)	(p. B-19-20): >90% (reduces CO >80%; reduces CO>50%; increases fuel consumption)	80 to 90% (pp. 5-7); Capital cost is $35,000; O&M is $6,000; Annualized capital is $4,851; TAC is $10,851; $571/ton (p. 8)
Convert RB to LB	(p. 45): not provided	—	—	—
EGR	(p. 49): up to 80% (increase power output by 10%; decrease fuel consumption by 7%)	—	—	—
Pre-stratified charge (converts RB to LB)	—	For 4S, RB, 2 g/bhp-hr (may de-rate engine power by 20%; costs significant) (p. 11)	(p. B-15): >80% (improved fuel efficiency)	—

[a]Some industry literature suggests that some particular 4S RB SI reciprocating engines can be converted to LB configurations with the accompanying LB engine NOx reduction capabilities. One vendor indicates that conversion to a LB configuration and the use of exhaust gas recirculation (EGR) delivers the advantages of a LB engine's efficiency and the RB engine's capability of utilizing NSCR for NOx control. The ability to convert a RB engine to a LB configuration is highly unit specific and does appear to have had widespread application in industry (p. 45). (OTC 2012)

Illinois: IEPA projected 2007 NOx emissions from 28 engines subject to the NOx SIP call to be 6,618 ton/season. NOx emission reductions from these sources were estimated to be 5,422 ton/season, and controlled NOx emissions levels were estimated to be 1,196 ton/season. (So baseline emissions were estimated to be 6,618 ton/season and controlled emissions were estimated to be 1,196 ton/season.) (IEPA 2007)

IEPA 2002 base year emissions inventory was 23,347 tpy NOx emitted from RICE and turbines, or approximately 8.4 percent of total point source NOx emissions (277,899 tpy NOx emissions from all point sources in Illinois) (p. 12). (IEPA 2007)

In addition to the NOx SIP Call requirements, IEPA also included additional units in its NOx regulation. NOx SIP Call units were to comply by May 2007, and additional units in NAA and AA were to comply in 2009, 2011, and 2012 (p. 51). The IL regulation will potentially affect 202 RICE engines and 36 turbines and reduce NOx emissions by 5,422 ton/season in 2007 ozone control season (p. 10). (IEPA 2007) [Full implementation of the IL regulation in 2012, to include additional units in NAA and AA counties down to the 500 hp size [28 NOx SIP Call units plus an additional 246 engines], was projected to reduce NOx emissions statewide by 17,082 tpy and 7,206 ton/season, which is 65 percent reduction on an annual basis and 55 percent reduction in O_3 season emissions (pp. 11 and 56). Uncontrolled NOx emissions in 2012 were projected to be 21,532 tpy and 9,134 ton/season, for those units included under the full implementation of the rule (p. 56). (IEPA 2007)]

Other Available Information

Additional RB control technologies and data are available in the OTC 2012.

Additional Diesel control technologies and data are available in OTC 2012.

References

(CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

(IEPA 2007). *Technical Support Document for Controlling NOx Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines*. AQPSTR 07-01. Illinois Environmental Protection Agency, Air Quality Planning Section, Division of Air Pollution Control, Bureau of Air. March 19, 2007.

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(CO DPHE). Reciprocating Internal Combustion Engine (RICE) Source Category, Reasonable Progress Evaluation for RICE Source Category. Colorado Department of Public Health and Environment – Air Pollution Control Division.

EPA Question 4: What are typical or realistic baseline and controlled NOx emissions factors (grams/hp-hr) for RICE in the OTC states?

Notes for Question 4

NOx control requirements for several of the Ozone Transport Commission (OTC) states were provided for Connecticut, New Jersey, New York, and Rhode Island, based on a 1994 STAPPA/ALAPCO document (p. 45). (IEPA 2007) These could potentially be used as maximum EF for RICE units. NOx control requirements are listed in the following table.

NOx Control Requirements for RICE in Some OTC States and Other States

State	Covered	NOx Control Level	Reference
Connecticut	≥3 MMBtu/hr (1175 hp)	Liquid-fired, CI: 8 g/bhp-hr (584 ppm)	IEPA 2007
New York	RACT for Major Facilities of NOx, Severe O_3 NAA ≥200 hp and Rest of state ≥400 hp	▪ Thru March 31, 2005, NG, RICE, LB: 3 g/bhp-hr (220 ppm) ▪ After April 1, 2005, LB: 1.5 g/bhp-hr (110 ppm) ▪ Thru March 31, 2005, Liquid-fired, CI: 9 g/bhp-hr (657 ppm) ▪ After April 1, 2005: 2.3 g/bhp-hr (168 ppm)	OTC 2012, DE 2012, IEPA 2007
New York (RACT)	Major facilities >25 tpy, NYC and Lower Orange Co: ≥200 kW Rest of state, major facilities >100 tpy: ≥400 kW	▪ NG: 1.5 g/bhp-hr ▪ Landfill or digester gas: 2.0 g/bhp-hr	
New Jersey		▪ NG, LB, ≥500 hp: 2.5 g/bhp-hr (182 ppm) ▪ Liquid-fired, CI, ≥500 hp: 8 g/bhp-hr (584 ppm)	IEPA 2007
New Jersey (RACT)	≥148 kW Group of 2 or more engines, each at ≥37 to <148 kW, but total combined power ≥148 kW	▪ Gas, LB: 1.5 g/bhp-hr, or 80% reduction ▪ Gas, RB: 1.5 g/bhp-hr	
New Jersey (RACT)	≥37 kW	▪ Commenced on or after March 7, 2007: 0.9 g/bhp-hr ▪ Modified on or after March 7, 2007: 0.9 g/bhp-hr, or 90% reduction	
Maryland	NG pipeline engines with >15% capacity factor	NA	IEPA 2007
Other States and Areas			
Illinois	NA	▪ 3 g/bhp-hr (210 ppm)	NA

(continued)

NOx Control Requirements for RICE in Some OTC States and Other States (continued)

State	Covered	NOx Control Level	Reference
Other States and Areas (cont.)			
SJVAPCD (amended 2011Aug18)	Rule 4702 ICE, SI and CI, nameplate rating ≥25 hp	▪ 2S, LB, NG, <100 hp: 75 ppmvd ▪ LB limited use or Gas compression: 65 ppmvd ▪ LB, all others: 11 ppmvd	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 2S, SI, LB, ≥500 hp: – Mfg before 9/23/1982: 8 g/bhp-hr – Mfg before 6/18/1992, <825 hp: 8 g/bhp-hr – Mfg btwn 9/23/1982 and 6/18/1992, >825hp: 5 g/bhp-hr – Mfg btwn 6/18/1992 and 6/1/2010: 2 g/bhp-hr (except 5 g/bhp-hr at reduced speed and torque 80-100%) – Mfg after 6/1/2010: 1 g/bhp-hr	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 4S, SI, LB: – Mfg before 9/23/1982, ≥500hp: 5 g/bhp-hr (except 8 g/bhp-hr at reduced speed and torque 80-100%) – Mfg before 6/18/1992, <825 hp: 5 g/bhp-hr (except 8 g/bhp-hr at reduced speed and torque 80-100%) – Mfg btwn 9/23/1982 and 6/18/1992, >825hp: 5 g/bhp-hr – Mfg btwn 6/18/1992 and 6/1/2010, ≥500hp: 2 g/bhp-hr (except 5 g/bhp-hr at reduced speed and torque 80-100%) – Mfg after 6/1/2010, ≥500hp: 1 g/bhp-hr ▪ After 1/1/2030, no 4S LB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 4S SI, LB, <500hp: ▪ Mfg before 7/1/2008: 2 g/bhp-hr ▪ After 1/1/2030: no 4S LB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.	OTC 2012
Texas (NAA major sources)	RACT, Major ICI, O3 NAA, Beaumont-Port Arthur O_3 NAA Major sources	▪ NG, SI, RICE, LB ≥300 hp: 3 g/bhp-hr ▪ NG, SI, RICE, RB, ≥300 hp: 2 g/bhp-hr	OTC 2012, DE 2012
Texas (NAA minor sources)	Combustion Control at Minor Sources in O_3 NAA, Houston-Galveston-Brazoria	▪ NG, RICE, >50 hp: 0.5 g/bhp-hr	DE 2012, ETCG 2013
Texas	O3 NAA, Dallas Ft. Worth	▪ RB, >50 hp: 0.5 g/hp-hr ▪ LB, >50 hp: – Installed or moved before June 2007: 0.7 g/hp-hr – Installed or moved after June 2007: 0.5 g/hp-hr	EDF 2008; ETCG 2013

(continued)

NOx Control Requirements for RICE in Some OTC States and Other States (continued)

State	Covered	NOx Control Level	Reference
Other States and Areas (cont.)			
Texas	East Texas Combustion Rule (existing engines comply by March 1, 2010; new engines comply at startup.)	▪ RB, NG, RICE, 240 to 500 hp: 1 g/hp-hr ▪ RB, NG, RICE, ≥500 hp: 0.5 g/hp-hr ▪ RB, Landfill gas, RICE, ≥500 hp: 0.6 g/hp-hr	ETCG 2013
Colorado	Regulation 7, RICE, LB, NG, New, modified, relocated	▪ After July 1, 2007, ≥500 hp: 2 g/bhp-hr ▪ After July 1, 2010, ≥500 hp: 1 g/bhp-hr ▪ After January 1, 2008, 100 to 500 hp: 2 g/bhp-hr ▪ After January 1, 2011, 100 to 500 hp: 1 g/bhp-hr	OTC 2012; CO DPHE
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	NG, SI, ICE	▪ Mfg after 7/1/2008, ≤25 hp, Class I: 11.0 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, ≤25 hp, Class I-B: 27.6 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, ≤25 hp, Class II: 8.4 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, 25 to 100 hp: 2.8 g/hp-hr of HC + NOx combined	ETGC 2013
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	SI, NG and SI, LB, LPG, 100 to 500 hp	▪ Mfg after 7/1/2008: 2 g/bhp-hr ▪ Mfg after 1/1/2011: 1 g/bhp-hr	ETCG 2013
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	NG and LPG, SI, LB, 500 to 1350 hp	▪ Mfg after 7/1/2008: 2 g/bhp-hr ▪ Mfg after 7/1/2010: 1 g/bhp-hr	OTC 2012
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	SI, NG and SI, LB, LPG (except LB 500 to 1350 hp)	▪ Mfg after 7/1/2007: 2 g/bhp-hr	ETCG 2013

NOx Control Requirements for RICE in Local Areas.

State or Area	Criteria	NOx control level	Reference
SCAQMD (July 2010)	Rule 1110.2 Emissions from Gaseous and Liquid Fueled Engines	▪ ≥500 hp: 0.5 g/bhp-hr (36 ppmvd) ▪ <500 hp: 0.6 g/bhp-hr (45 ppmvd) ▪ After July 1, 2010, ≥500 hp: 0.15 g/bhp-hr (11 ppmvd) ▪ After July 1, 2010, <500 hp: 0.6 g/bhp-hr (45 ppmvd) ▪ After July 1, 2011, All: 0.15 g/bhp-hr (11 ppmvd)	OTC 2012

For engines with unknown pre-rule emissions, NOx emissions were assumed to be 16.4 g/bhp-hr for 2S and 18.9 g/bhp-hr for 4S. (DE 2012)

A list of Stack test results for engines in PA that are >500 hp are given in Appendix A, Table 3 of the PA DEP 2013 reference (p. 53). (PA DEP 2013) [Capital] costs for NSCR, RB ranged from $10 to $12/bhp. (p. 9) NSCR, RB ranged from $10 to $15/bhp (slightly different value given here). (p. 16) (MECA 1997)

IC Engine Typical Emissions Levels (MECA 1997)

Engine Type	Lambda (Actual A/F ratio to Stoichiometric A/F ratio)	Mode	NOx, g/bhp-hr
NG	0.98	Rich	8.3
	0.99	Rich	11.0
	1.06	Lean	18.0
	1.74	Lean	0.7
Diesel	1.6–3.2	Lean	11.6
Dual Fuel	1.6–1.9	Lean	4.1

For RB, CARB 2001 document has Costs for NSCR w/o AFRC achieving 96% reduction. Capital costs ranged from $11,000 to $44,000; Annual costs ranged from $8,200 to $18,000; and cost effectiveness ranged from $2,100/ton to $300/ton NOx reduction (p. V-2 to V-3). (CARB 2001)

For RB, CARB 2001 document has Costs for Pre-stratified Charge, achieving 80% reduction. Capital costs ranged from $10,000 to $47,000; Annual costs ranged from $2,700 to

$11,000; and cost effectiveness ranged from $800/ton to $200/ton NOx reduction (pp. V-2 to V-3). (CARB 2001)

CARB 2001 document has costs for Ignition Timing Retard (ITR), although the description of the combustion technology indicates it is less popular on Stationary engines than mobile source engines (pp. V-2, B-7 to B-8). (CARB 2001)

The EDF 2008 reference provided NOx EF for engines in the Bartlett Shale region. The document notes that extending the 2009 engine rules in Barnett Shale to counties outside the DFW NAA would likely result in many engine operators installing NSCR on RB engines. NSCR costs were cited as follows: $330/ton (IEPA 2007); $92 to $105/ton (EPA 2006); and $112 to $183/ton (northeast Texas 2005 report). Another control technique reviewed in this report included replacement of compressor engines with electric motors. There are multiple compressors driven by electric motors throughout Texas (p. 26). Use of electric motors instead of gas-fired engines eliminates combustion emissions (p. 27). The costs are time and site specific, based on the cost of electricity, cost of NG, hours of operation per year, number of compressors, size of compressor, etc. (EDF 2008)

NOx Emission Factors for Engines Identified in DFW 2007 Engine Survey (EDF 2008)

2007 EF			2009 EF		
Engine Type	**Engine Size, hp**	**NOx, g/hp-hr**	**Engine Type**	**Engine Size, hp**	**NOx, g/hp-hr**
RB	<50	13.6	RB	<50	13.6
RB	50–500	13.6	RB	50–500	0.5
RB	>500	0.9	RB	>500	0.5
LB	<500	6.2	LB, installed or moved before June 2007	<500	0.62
LB	>500	0.9	LB, installed or moved after June 2007,	<500	0.5
___	___	___	LB, installed or moved before June 2007	>500	0.7
___	___	___	LB, installed or moved after June 2007	>500	0.5

References

(MECA 1997). *Emission Control Technology for Stationary Internal Combustion Engines: Status Report*. Manufacturers of Emission Controls Association (MECA). July 1997.

(CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

(IEPA 2007). *Technical Support Document for Controlling NOx Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines*. AQPSTR 07-01. Illinois Environmental Protection Agency, Air Quality Planning Section, Division of Air Pollution Control, Bureau of Air. March 19, 2007.

(EDF 2008). *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost Effective Improvements.* Conducted by Department of Environmental and Civil Engineering, Southern Methodist University, for Environmental Defense Fund. Peer-Review Draft. September 30, 2008.

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(ETCG 2013). *Gas Compressor Engine Study for Northeast Texas, for East Texas Council of Governments*. Prepared by ENVIRON International Corporation, for East Texas Council of Governments. June 2013.

(CO DPHE). *Reciprocating Internal Combustion Engine (RICE) Source Category, Reasonable Progress Evaluation for RICE Source Category*. Colorado Department of Public Health and Environment—Air Pollution Control Division.

EPA Question 5: Using FERC data or other data sources, what is the relationship between RICE model and age, and emissions (both for baseline and with controls)? In particular, what is the relationship for RICE built before the imposition of the SI (spark ignition, natural gas-fired) RICE NSPS in 2007?

Notes for Question 5

The DE 2012 reference stated that many of the installed mainline NG compressors are of the age (in excess of 40 years old) to have pre-dated modern original equipment manufacturer (OEM) installed NOx emission controls and otherwise applicable new source performance standards (NSPS). There is little information on the number of units that may have undergone NOx modifications as a result of federal or State rules and regulations. The reference cited a 2003 Pipeline Research Council International (PRCI) document that identified 5,686 engines: 71% are LB and 29% are RB (based on dropping the turbine numbers in the table below). The average age for each unit type is shown in the following table. [These data are repeated in OTC 2012.] [Based on these data, it is estimated that the LB and RB engines are 37 years old on average (based on dropping the turbine numbers in the table below).] (p. 19) (DE 2012)

2003 Pipeline Research Council International Data (PRCI)

Unit Type	U.S Total Units (%)	Average Age (as of 2003)	Avg hp
2S LB	2,955 (44%)	42	2,113
4S LB	1,059 (16%)	33	1,844
RB	1,672 (25%)	32	589
Turbine	1,016 (15%)	24	6,121

The OTC 2012 reference indicated that many of the reciprocating engines driving mainline NG compressors are in excess of 40 years old, pre-dating any applicable modern OEM installed NOx emission control and any otherwise applicable NSPS NOx controls (p. 16). (OTC 2012)

The DE 2012 reference discussed a 2005 study conducted for NG field gathering engines in Eastern Texas; the study was able to determine the age only for a very small portion of the engines, and the engine age ranged from 2 to 25 years. The output ratings of engines in the study ranged from 26 to 1478 hp, with the majority rated between 50 and 200 hp (p. 12). (DE 2012)

The DE 2012 reference indicated they reviewed MARAMA's 2007 Point Source Inventory and 2007 FERC data. The 2007 FERC data are provided as Attachment III to the reference. The two sets of data did not match: 2007 MARAMA data indicated 107 compressor facilities, and 2007 FERC data indicated 150 compressor facilities. The reviewed databases did not provide any information regarding NOx emission rates (g/bhp-hr, ppmvd). NOx emission rates were obtained for a small number of prime movers, through operating permits: 2SLB range from 1 to 13.3 g/bhp-hr; 4SLB range from 0.5 to 6 g/bhp-hr; and 4SRB were 3 g/bhp-hr. The data are not sufficient to estimate actual NOx emission rates and NOx reductions. Note that the FERC data addresses large entities, and smaller companies may not be required to report data to FERC. The 2007 OTC compressors from FERC are provided in the following table. (DE 2012)

State	No. Compressors	Total Rated hp
CT	10	35,300
MA	15	25,702
MD	17	52,250
ME	4	33,244
NJ	36	129,130
NY	120	359,487
PA	467	1,331,164
RI	6	29,170
VA (OTR area only)	22	49,390

The KSU 2011 reference discussed control technologies testing performed in the laboratory on a 1966 Ajax DP-115 (Lean Burn) that has none of the low emissions controls that are currently OEM standard. The published emission factor (EF) for this engine is 4.4 g/bhp-hr, and the emissions from actual testing were 4.69±0.18 g/bhp-hr (the Lab testing results are discussed on pp. 19-27). There is additional discussion of Field testing conducted on multiple LB engines with NOx emission control techniques, including (1) Increased air flow, and precombustion chamber (PCC) screw-in type, (2) PCC screw-in type and Upgraded turbocharger, (3) Integral PCC and high-output turbocharger (pp. 27-29). Discussion of Field testing conducted on two RB engines with NOx emission control techniques (p. 29). Integrated nonselective catalytic reduction (NSCR) with modeling and enhanced controller is also discussed. (KSU 2011).

References

(KSU 2011). *Final Report: Cost-Effective Reciprocating Engine Emissions Controls and Monitoring for E&P Field and Gathering Engines*. K. Hohn and S. Nuss-Warren, Kansas State University. November 2011.

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(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final.* October 17, 2012.

EPA Question 6: What is the variability in NOx emissions from RICE within each State, both for baseline and with controls?

Notes for Question 6

No data were found. [Likely a review of RICE SCCs in the NEI across states would be a useful exercise to see the relative levels of baseline and/or controlled NOx emissions, however this exercise was not part of this task.]

To: US EPA OAQPS

From: SRA International, Inc.

Subject: Review of CoST Model Emission Reduction Estimates

Date: September 30, 2014

EPA uses the Control Strategy Tool (CoST) to estimate the emission reductions and engineering costs associated with control strategies applied to point, area, and mobile sources of air pollutant emissions to support the analyses of air pollution policies and regulations. CoST accomplishes this by matching control measures to emission sources using algorithms such as "maximum emissions reduction", "least cost", and "apply measures in series". There was a concern that the baseline inventory used by CoST did not completely account for emission control requirements already in place, and that the emission reductions were perhaps overestimated.

SRA reviewed the CoST results and made recommendations for changing the CoST control measure assignment and the estimated reductions for oxides of nitrogen (NOx). The recommendations were based on a review of source permits, state regulations, enforcement actions, and other available information. The analysis was conducted for a 24-state area in the eastern two-thirds of the U.S. The focus was on stationary point sources other than electric generating units (non-EGUs). The purpose of this memo is to document the data used and assumptions made in recommending changes to the CoST results, and to summarize the differences between the CoST results and the recommended changes.

The findings in this memo are based on review of CoST results for a 2018 emissions inventory projected from the 2011 National Emission Inventory (NEI). This work was in support of EPA's current Transport Rule efforts for implementing the 75 ppb ozone standard. If EPA considers establishing a tighter ozone standard in the future, it is likely that a more distant future year will be used and that some of the conclusions reached in this memo could change.

CoST DATA PROVIDED BY EPA

EPA provided SRA with the outputs from a CoST scenario that identified sources for which NOx controls were available at a cost-effectiveness level of less than $10,000 per ton. The CoST outputs included source identifiers, control technology, baseline emissions and estimates of NOx emission reductions. The CoST results were divided into two groups. The first group included sources where CoST estimated NOx emission reductions of more than 100 tons per year. There were 547 sources in this group where CoST controls were initially applied. The second group included sources where CoST estimated emission reductions for sources whose 2018 projected emissions were greater than 25 tons/year, excluding those with reductions greater than 100 tons/year. There were 1,280 sources in this group where CoST controls were initially applied.

Another contractor reviewed the CoST results for additional source categories, and their recommendations were merged with SRA's recommendations in the summary tables and maps that follow. The data used, assumptions made and results for IC engines are documented elsewhere[1].

REVIEW OF CoST RESULTS FOR THE GREATER THAN 100 TPY GROUP

Table 1 summarizes the source categories included in our analysis, the CoST recommendation for NOx control, and the recommendation for changing the CoST control measure assignment and associated emission reduction estimates. Following Table 1, there is a discussion for each source group to provide more detail on the rationale for the recommended changes for each source group. Attachments 1 to 4 are tabular comparisons of the initial CoST emission reduction estimates and the recommended changes. All Attachments present the results in terms of tons per ozone season, simply estimated by assuming that ozone season emissions were equal to 5/12 of the annual emissions. Maps 1A and 1B graphically show the location of sources and the magnitude of the recommended emission reductions.

Table 1 – CoST Controls and Recommended Changes for Greater than 100 TPY Sources

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Ammonia – NG-fired Reformers	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
By-Product Coke Mfg; Oven Underfiring	Selective Non-Catalytic Reduction	Review of a source-specific NOx RACT permit indicated that NOx controls were technically or economically infeasible.
Cement Kilns	Biosolid Injection Technology	Disagreed with CoST recommendation based on concerns about biosolids availability and information from EPA's ISIS (Industrial Sector Integrated Solutions) Model; recommended SNCR for all sources, except those that already have SNCR due to NOx SIP Call, NSR requirement, Consent Decree, or other state regulation.

[1] Update of NOx Control Measure Data in the CoST Control Measures Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines,Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines," prepared by Research Triangle Institute, July 2014.

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Cement Manufacturing - Dry	Selective Non-Catalytic Reduction	Agreed with CoST recommendation except when already controlled due to NOx SIP Call, NSR requirement, Consent Decree, or other state regulation.
Cement Manufacturing – Wet	Mid-kiln Firing	Disagreed with CoST recommendation based on information from EPA's ISIS Model; recommended SNCR for all sources, except those that already controlled
Coal Cleaning – Thermal Dryer	Low NOx Burner	Agreed with CoST recommendation
Comm/Inst Incinerators	Selective Non-Catalytic Reduction	Both sources are already controlled with SNCR
External Combustion Boilers, Elec Gen, Solid Waste	Selective Non-Catalytic Reduction	All 6 sources are already controlled with SNCR
Fluid Catalytic Cracking Units	Low NOx Burner and Flue Gas Recirculation	Nearly all FCCUs are already controlled due to the OECA global refinery consent decrees. There is one small refinery in West Texas that does not appear to be covered by a consent decree, so the CoST recommendation was accepted.
Glass Manufacturing – Container, Flat, Pressed	OXY-Firing	Disagreed with CoST recommendation. OXY-firing is not generally required under recent OECA consent decrees. More common control is oxygen-enriched air staging (OEAS). OXY-firing can only be implemented at the time of furnace rebuild, which is generally done every 10-15 years. Changed recommended control to OEAS with a 50% NOx reduction instead of OXY-firing at 85% NOx reduction, except for sources that already had NOx controls in place due to a consent decree, NSR requirement, or state regulation. Assumed that a furnace with a NOx emission limit of less than 4 lbs/ton of glass pulled was already reasonably controlled.
ICI Boilers – Coal/Cyclone	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled. LADCO/OTC also recommends SCR
ICI Boilers – Coal/Stoker	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has $2200/ton, which appears

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
		very low for ICI boilers. Used LADCO/OTC recommendation of SNCR for Coal-Stokers with a 50% reduction, except for those sources where a permit or state regulation already required the source to be controlled.
ICI Boilers – Coal/Wall	Low NOx Burner and Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled. LADCO/OTC also recommends LNB/SCR
ICI Boilers – Gas, Natural Gas, Process Gas	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has $3456/ton, which appears very low for ICI boilers. Used LADCO/OTC recommendation of Low NOx Burners plus Flue Gas Recirculation for Gas-fire ICI boilers with a 60% reduction, except for those sources where a permit or state regulation already required the source to be controlled
Industrial Incinerators	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a permit or state regulation already required the source to be controlled.
Iron & Steel Mills – Reheating	Low NOx Burner and Flue Gas Recirculation	Agreed with CoST recommendation except for those sources where a permit or state regulation already required the source to be controlled.
Municipal Waste Combustors	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a permit or state regulation already required the source to be controlled.
Nitric Acid Manufacturing	Nonselective Catalytic Reduction	Agreed with CoST recommendation of NSCR except for those sources where a permit or state regulation already required the source to be controlled.
Petroleum Refinery Process Heaters	SCR-95%	Nearly all refineries are already controlled due to the OECA global refinery consent decrees, which generally require 40-60% reductions across all boilers/heaters that each company operates. Not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be controlled due to confidentiality agreements between EPA and companies.

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Taconite Ore Processing – Induration – Coal or Gas	Selective Catalytic Reduction	Disagree with CoST recommendation of SCR. EPA Region V considers SCR/SNCR to be infeasible. Used Low NOx Burners at 70% reduction instead as reasonable control, except for those sources where a permit or state regulation already required the source to be controlled. .
Utility Boilers* – Coal/Wall	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
Utility Boilers* – Oil/Gas	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.

The utility boilers included in the context of this report are non-IPM utility boilers. In the NEI, these units have an SCC of 1-01—xxx-xx (the SCC series generally used for electric generating units. However, the sources included in this analysis do not sell electricity to the grid.

Ammonia – NG-fired Reformers

There are 15 sources in this category. The CoST control technology was selective catalytic reduction (SCR) with a 90% reduction in NOx emissions. We determined that four of these sources were already controlled by either SCR or ultra-NOx burners and recommended no further control/reductions. For all other sources, we agreed with the CoST control and emission reduction estimate.

By-Product Coke Mfg; Oven Underfiring

There are 14 sources in this category. The CoST control technology was selective non-catalytic reduction (SNCR) with a 60% reduction in NOx emissions. We reviewed a detailed RACT analysis for a facility in Pennsylvania that determined that no controls were feasible. For all sources in this category, we recommended that no controls were feasible and thus no reductions were appropriate.

Cement Preheater/Precalciner Kilns

There are 36 sources in this category. The CoST control technology was biosolid injection technology with a 23% reduction in NOx emissions. We reviewed permits and consent decrees to identify those kilns that are already controlled. Several kilns are already controlled based on NOx SIP Call requirements that typically required low NOx burners, mid-kiln firing, or an approved alternative that resulted in a 30% reduction. Other kilns already had SNCR installed due to a consent decree, new source review requirement, or other state-level requirement.

EPA expressed a concern whether there was sufficient biosolids availability for use by the uncontrolled kilns. Also, EPA has done considerable research on cement kiln NOx controls as part of its Industrial Sector Integrated Solutions (ISIS) project. EPA uses the ISIS-cement model help analyze policy options for various rulemakings. Based on the ISIS work, we recommended that low-NOx burners and SNCR as the appropriate control for all types of kilns.

For uncontrolled kilns, we applied a 65% reduction in NOx emissions. For kilns already controlled with low-NOx burners or mid-kiln firing, we applied a 35% incremental reduction to account for the additional reductions from SNCR. For kilns already controlled with SNCR, we applied no additional emission reductions.

Cement Manufacturing - Dry Process

There are 20 sources in this category. The CoST control technology was SNCR with a 50% reduction in NOx emissions. We reviewed permits and consent decrees to identify those kilns that are already controlled. Several kilns are already controlled based on NOx SIP Call requirements that typically required low NOx burners, mid-kiln firing, or an approved alternative that resulted in a 30% reduction. Other kilns already had SNCR installed due to a consent decree, new source review requirement, or other state-level requirement.

As discussed earlier, we recommended that low-NOx burners and SNCR as the appropriate control for all types of kilns based on the ISIS work. For uncontrolled kilns, we applied a 65% reduction in NOx emissions. For kilns already controlled with low-NOx burners or mid-kiln firing, we applied a 35% incremental reduction to account for the additional reductions from SNCR. For kilns already controlled with SNCR, we applied no additional emission reductions.

Cement Manufacturing – Wet Process

There are seven sources in this category. The CoST control technology was mid-kiln firing with a 30% reduction in NOx emissions. We determined that two of these kilns were installing a pilot SCR system as part of a consent decree. One kiln recently went through NSR review and has state-of-the-art control. Another kiln is required to install SNCR as part of a consent decree. No additional reductions were applied for these kilns. For the remaining kilns, we applied low-NOx burners and SNCR as described in the previous sections.

Coal Cleaning – Thermal Dryer

There was one source in this category. The CoST control technology was a low-NOx burner with a 50% reduction in NOx emissions. We could not find any information on this source and accepted the CoST controls.

Comm/Inst Incinerators

There are two sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. Both of these sources are already controlled by SNCR and we applied no additional emission reductions.

External Combustion Boilers, Elec Gen, Solid Waste

There are six sources in this category. The CoST control technology was SNCR with a 50% reduction in NOx emissions. All six of these sources are already controlled by SNCR and we applied no additional emission reductions.

Fluid Catalytic Cracking Units

There are six sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 55% reduction in NOx emissions. Nearly all sources are already controlled or required to install controls as a result of the EPA's global refinery consent decrees. There is one small refinery in West Texas that does not appear to be covered by a consent decree, so the CoST recommendation was accepted.

Glass Manufacturing – Container, Flat, Pressed

There are 65 sources in this category. The CoST control technology was oxy-firing with an 85% reduction in NOx emissions. There were several concerns about using oxy-firing for this analysis. First, there is a concern about the timing of installing oxy-firing technology. Oxy-firing is typically installed at the time of a furnace rebuild, which is typically done every 10 to 15 years. Second, oxy-firing is not generally required under recent EPA consent decrees. More common control is oxygen-enriched air staging (OEAS). We recommended that OEAS with a 50% NOx reduction instead of OXY-firing at 85% NOx reduction, except for sources that already had NOx controls in place due to a consent decree, NSR requirement, or state regulation. We assumed that a furnace with a NOx emission limit of less than 4 lbs/ton of glass pulled was already reasonably controlled.

ICI Boilers – Coal/Cyclone

There are eight sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. We reviewed the *Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers Technical Support Document (TSD), March, 2011* prepared by the Lake Michigan Air Directors Consortium (LADCO) and the Ozone Transport Commission (OTC). LADCO/OTC also recommended SCR for coal-cyclone boilers. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology for five sources which we determined were uncontrolled. Two sources were determined to be already controlled. One source appears to have shut down their coal-fired boilers. No reductions were applied for these three sources since they are already controlled.

ICI Boilers – Coal/Stoker

There are 45 sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. The LADCO/OTC recommendation was for combustion tuning and SNCR. We agreed with the LADCO/OTC recommendation and assumed a 50% control efficiency. We determined that most of these sources are currently uncontrolled. Two coal-fired boilers are scheduled to be replaced with gas-fired boilers. Two other boilers recently installed SNCR.

ICI Boilers – Coal/Wall

There are 54 sources in this category. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was also for low-NOx burners and SCR. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology and emission reductions.

ICI Boilers – Gas, Natural Gas, Process Gas

There are 130 sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners, flue gas recirculation, or low-NOx burners combined with flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 60% control efficiency.

Several of these sources are located in the OTR or ozone nonattainment areas, and as a result already have a RACT control requirement or emission limitation that is consistent with the LADCO/OTC recommendations. A few of these sources are located at petroleum refineries and were assumed to be already controlled due to EPA's refinery enforcement initiative.

Municipal Waste Combustors

There are 55 sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We determined that 35 of these sources are already controlled with SNCR and no additional reductions were applied. For the remaining uncontrolled sources, we agreed with the CoST controls and emission reductions.

Nitric Acid Manufacturing

There are seven sources in this category. The CoST control technology was non-selective catalytic reduction (NSCR) with a 98% reduction in NOx emissions. All but one of these sources is already controlled by NSCR or SCR.

Petroleum Refinery Process Heaters

There are 28 sources in this category. The CoST control technology was SCR with a 95% reduction in NOx emissions. All of the sources in this category are covered sources under EPA's global refinery enforcement initiative. The settlements generally require 40-60% reductions across all boilers/heaters that each company operates. Companies have submitted NOx compliance plans to OECA that identify the specific sources that have been controlled or are planned to be controlled, along with the technology used. But it is not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be controlled due to confidentiality agreements between EPA and companies. No additional reductions were included for this category.

Taconite Ore Processing – Induration – Coal or Gas

There are 10 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. All of the sources in this category are already subject to Best Available Retrofit Technology (BART) requirements under the Regional Haze program. EPA Region V determined that BART is low-NOx burners and agreed that SCR controls are infeasible for indurating furnaces. No additional reductions were included for this category.

Utility Boilers – Coal/Wall, Oil, Gas

There are 11 sources in this category. The CoST control technology was SCR with a 80 to 90% reduction in NOx emissions depending on fuel type. All of the sources in this category appear to be uncontrolled and we agreed with the CoST control and emission reduction estimate.

REVIEW OF CoST RESULTS FOR THE 25 TO 100 TPY GROUP

Due to the large number of sources in this group, we were not able to review individual permits to determine whether the individual source was already controlled. Instead, our recommendations were based on of state regulations, enforcement actions, engineering judgment, and other available information. We generally assumed that sources located in areas with stringent NOx rules are already well controlled and we assumed that no additional reductions were likely from these sources. This assumption was generally applied in New Jersey, New York and sources located in the Houston nonattainment area. Given more time, we would like to have also applied this assumption in other areas with stringent existing regulations, such as Chicago, Milwaukee, and Baton Rouge. In any future analysis, it would be useful to examine the stringency of rules that apply strictly to nonattainment areas.

Table 2 summarizes the source categories included in our analysis, the CoST recommendation for NOx control, and the recommendation for changing the CoST control measure assignment and associated emission reduction estimates. Following Table 2, there is a discussion for each source group to provide more detail on the rationale for the recommended changes for each source group. Attachments 5 to 8 are tabular comparisons of the initial CoST emission reduction estimates and the recommended changes. All Attachments present the results in terms of tons per ozone season, simply estimated by assuming that ozone season emissions were equal to 5/12 of the annual emissions. Maps 3A and 3B graphically show the location of sources and the magnitude of the recommended emission reductions.

Table 2 – CoST Controls and Recommended Changes for 25 to 100 TPY Sources

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Ammonia – NG-fired Reformers	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
Cement Kilns	Biosolid Injection Technology	Because of low emissions, assume that the kiln is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
Cement Manufacturing – Wet	Mid-kiln Firing	Because of low emissions, assume that the kiln is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
Ceramic Clay Mfg; Drying	Low NOx Burner	Questions about technical feasibility for these category, assume zero reductions
Coal Cleaning – Thermal Dryer	Low NOx Burner	Agree with CoST recommendation
Comm/Inst Incinerators	Selective Non-Catalytic Reduction	Agree with CoST recommendation
External Combustion Boilers, Elec Gen, Sub/Bit Coal	Selective Non-Catalytic Reduction	Agree with CoST recommendation, although questions as to whether the source is already controlled or very low usage which would result in a unreasonably high cost-effectiveness
Fluid Catalytic Cracking Units	Low NOx Burner and Flue Gas Recirculation	Nearly all FCCUs are already controlled due to the OECA global refinery consent decrees.
Gas Turbines	Low NOx Burners	Agreed with CoST recommendation except for those sources where a state regulation already required the source to be controlled.
Glass Manufacturing – Container, Flat, Pressed	OXY-Firing	Because of low emissions, assume that the furnace is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
ICI Boilers – Coal/Stoker	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has $2200/ton, which appears very low for ICI boilers. Used LADCO/OTC recommendation of SNCR for Coal-Stokers with a 50% reduction, except for those sources where a state regulation already required the source to be controlled.
ICI Boilers – Coal/Wall	Low NOx Burner and Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
		controlled. LADCO/OTC also recommends LNB/SCR
ICI Boilers – Distillate Oil or Process Gas	Selective Catalytic Reduction	Because of low emissions, assume that the boiler is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
ICI Boilers – Natural Gas	Low NOx Burner and Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. Used LADCO/OTC recommendation of Low NOx Burners plus Flue Gas Recirculation for Gas-fire ICI boilers with a 60% reduction, except for those sources where a permit or state regulation already required the source to be controlled
ICI Boilers – Residual Oil	Low NOx Burner and Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be controlled.
Industrial Incinerators	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a state regulation already required the source to be controlled.
Iron & Steel Mills – Reheating	Low NOx Burner and Flue Gas Recirculation	Agreed with CoST recommendation except for those sources where a state regulation already required the source to be controlled.
Municipal Waste Combustors	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a state regulation already required the source to be controlled.
Nitric Acid Manufacturing	Nonselective Catalytic Reduction	Agreed with CoST recommendation of NSCR except for those sources where a state regulation already required the source to be controlled.
Petroleum Refinery Process Heaters	SCR or Ultra-Low NOx Burner	Nearly all refineries are already controlled due to the OECA global refinery consent decrees, which generally require 40-60% reductions across all boilers/heaters that each company operates. Not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be control due to confidentiality agreements between EPA and companies.
Utility Boilers – Coal/Wall	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be controlled
Utility Boilers – Oil/Gas	Selective Catalytic Reduction	Because of low emissions, assume unreasonably high cost-effectiveness for SCR; use LNB/FGR as reasonable control.

Ammonia – NG-fired Reformers

There are seven sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. For all other sources, we agreed with the CoST control and emission reduction estimate.

Cement Kilns

There are six sources in this category. The CoST control technology was either biosolid injection technology with a 23% reduction in NOx emissions or mid-kiln firing with a 30% reduction. Because of the low baseline emissions for these kilns, we assumed that the kilns were already controlled or have low usage which would result in a very high cost-effectiveness. We determined that no reductions be applied for these sources.

Coal Cleaning – Thermal Dryer

There are 10 sources in this category. The CoST control technology was a low-NOx burner with a 50% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Commercial/Institutional Incinerators

There are four sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

External Combustion Boilers, Electric Generation, Coal

There are 14 sources in this category. The CoST control technology was SNCR with a 40% reduction in NOx emissions. It appears that the sources in this category are low usage spreader stokers. Although there may be a concern about the cost-effectiveness for these sources, we agreed with the CoST control and emission reduction estimate.

Fluid Catalytic Cracking Units

There are 21 sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 55% reduction in NOx emissions. All sources in this category are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative. Additionally, eight of the sources are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions for the FCCUs.

Gas Turbines

There are 438 sources in this category. The CoST control technology was for low-NOx burners with a 68% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Glass Manufacturing – Container, Flat, Pressed

There are eight sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. Because of the low baseline emissions for these furnaces, we assumed that the furnaces were already controlled and determined that no reductions be applied for these sources.

ICI Boilers – Coal/Stoker

There are 133 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. The LADCO/OTC recommendation was for combustion tuning and SNCR. We agreed with the LADCO/OTC recommendation and assumed a 50% control efficiency.

ICI Boilers – Coal/Wall

There are 11 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was also for low-NOx burners and SCR. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology and emission reductions.

ICI Boilers – Natural Gas

There are 376 sources in this category. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners, flue gas recirculation, or low-NOx burners combined with flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 50% control efficiency, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

ICI Boilers – Process Gas

There are 57 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. Most of these sources are located at petroleum refineries and are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative, or are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions.

ICI Boilers – Residual Oil

There are 28 sources in this category. The CoST control technology was low-NOx burner and SNCR with a 69.5% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Industrial Incinerators

There are 21 sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Iron & Steel Mills – Reheating

There are 32 sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 77% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Municipal Waste Combustors

There are 25 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. RTI identified the sources are already controlled and no additional reductions were applied for these sources. For the remaining sources, we agreed with the CoST controls and emission reductions.

Nitric Acid Manufacturing

There are 14 sources in this category. The CoST control technology was NSCR with a 98% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Petroleum Refinery Process Heaters

There are 30 sources in this category. The CoST control technology was SCR with a 90-98% reduction or ultra-low NOx burners with a 30-50% reductions in NOx emissions. Most of these sources are located at petroleum refineries and are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative, or are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions.

Utility Boilers – Coal/Wall

There are three sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Utility Boilers – Oil/Gas

There are 27 sources in this category. The CoST control technology was SCR with a 80% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners or flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 60% control efficiency.

Attachment 1 – NOx Emission Reductions by State for Sources in the > 100 Ton per Year Reduction Group

State	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Alabama	24	2,855	2,287	568
Arkansas	6	455	293	162
Delaware	2	206	0	206
Florida	20	2,158	1,370	788
Illinois	21	2,659	1,472	1,187
Indiana	41	5,405	4,510	896
Iowa	10	1,226	999	227
Kansas	7	735	452	283
Kentucky	11	915	838	77
Louisiana	57	7,623	3,622	4,000
Maryland	10	1,933	355	1,578
Michigan	27	2,758	1,768	990
Mississippi	7	1,054	516	538
Missouri	15	1,698	1,562	136
New Jersey	15	417	0	417
New York	30	3,091	281	2,810
Ohio	37	4,098	2,039	2,058
Oklahoma	20	2,949	1,864	1,086
Pennsylvania	52	5,637	2,215	3,422
Tennessee	13	4,741	1,987	2,755
Texas	65	8,860	6,383	2,477
Virginia	28	3,337	3,033	303
West Virginia	9	1,180	793	387
Wisconsin	20	4,092	3,416	676
	547	**70,082**	**42,054**	**28,028**

Attachment 2 – NOx Emission Reductions by Source Group for Sources in the > 100 Ton per Year Reduction Group

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Ammonia - NG-Fired Reformers	15	2,427	1,551	875
By-Product Coke Mfg; Oven Underfiring	14	1,199	0	1,199
Cement Kilns	36	3,932	6,586	-2,654
Cement Manufacturing - Dry	20	3,672	2,234	1,438
Cement Manufacturing - Wet	7	1,294	1,120	174
Coal Cleaning-Thrml Dryer; Fluidized Bed	1	50	50	0
Comm./Inst. Incinerators	2	137	0	137
External Combustion Boilers, Solid Waste	6	472	0	472
Fluid Cat Cracking Units; Cracking Unit	6	607	52	556
Fuel Fired Equip; Process Htrs; Pro Gas	2	143	143	0
Glass Manufacturing - Container	34	2,759	678	2,081
Glass Manufacturing – Flat	23	10,241	6,024	4,217
Glass Manufacturing - Pressed	8	684	402	282
ICI Boilers - Coal/Cyclone	8	2,987	1,840	1,147
ICI Boilers - Coal/FBC	3	233	180	53
ICI Boilers - Coal/Stoker	45	4,688	2,938	1,750
ICI Boilers - Coal/Wall	54	12,041	7,996	4,045
ICI Boilers – Gas	10	1,266	910	356
ICI Boilers - Natural Gas	84	7,578	3,452	4,126
ICI Boilers - Process Gas	36	3,868	1,229	2,639
ICI Boilers - Residual Oil	2	199	82	117
Indust. Incinerators	9	586	124	461
In-Proc;Process Gas;Coke Oven/Blast Furn	3	299	0	299

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
In-Process; Bituminous Coal; Cement Kiln	2	290	295	-5
Iron & Steel - In-Process Coal Combustion	4	419	0	419
Iron & Steel Mills – Reheating	2	156	156	0
Municipal Waste Combustors	55	1,591	876	715
Nitric Acid Manufacturing	7	687	82	605
Petroleum Refinery Gas-Fired Process Heaters	28	2,025	0	2,025
Taconite Iron Ore - Induration - Coal or Gas	10	829	451	379
Utility Boiler - Coal/Wall	5	555	555	0
Utility Boiler - Oil-Gas/Tangential	2	526	526	0
Utility Boiler - Oil-Gas/Wall	4	1,645	1,524	121
	547	**70,082**	**42,054**	**28,028**

Attachment 3 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the > 100 Ton per Year Reduction Group

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
211 Oil and Gas Extraction	1	46	30	16
212 Mining (except Oil and Gas)	11	879	500	379
221 Utilities	10	1,186	853	333
311 Food Mfg	12	1,181	815	366
312 Beverage and Tobacco Product Mfg	7	761	761	0
322 Paper Mfg	70	11,616	7,968	3,648
324 Petroleum and Coal Products Mfg	49	3,942	239	3,703
325 Chemical Mfg	132	19,689	10,753	8,937
3272 Glass and Glass Product Mfg	64	13,588	7,047	6,540
3273 Cement and Concrete Product Mfg	64	9,113	10,183	-1,070
3274 Lime & Gypsum Product Mfg	1	75	52	22
331 Primary Metal Mfg	50	4,908	1,837	3,070
333 Machinery Mfg	1	57	35	21
336 Transportation Equipment Mfg	2	148	103	46
424 Merchant Wholesalers, Nondurable Goods	2	160	0	160
531 Real Estate	1	72	0	72
562 Waste Mgmt and Remediation Services	65	2,366	843	1,523
611 Educational Services	5	295	34	261
	547	**70,082**	**42,054**	**28,028**

Attachment 4 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the > 100 Ton per Year Reduction Group

Recommended Change to CoST Control	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Already Controlled	138	12,973	0	12,973
Already Controlled by Glass CD	12	1,034	0	1,034
Already Controlled By Refinery CD	52	4,300	0	4,300
Control Technically or Economically Infeasible	18	1,618	0	1,618
Fuel Switch Already Occurred	4	2,370	0	2,370
Low NOx Burner	7	629	500	129
Low NOx Burner and Flue Gas Recirculation	88	8,792	6,022	2,769
Low NOx Burner and SCR	44	7,996	7,996	0
Low NOx Burner and SNCR	41	5,895	10,236	-4,341
Non-Selective Catalytic Reduction	1	82	82	0
Oxygen Enriched Air Staging	47	12,077	7,104	4,973
Selective Catalytic Reduction (SCR)	27	6,088	6,088	0
Selective Non-Catalytic Reduction (SNCR)	62	5,109	4,026	1,083
Source Already Shutdown	6	1,120	0	1,120
	547	**70,082**	**42,054**	**28,028**

Attachment 5 – NOx Emission Reductions by State for Sources in the 25 to 100 Ton per Year Reduction Group

State	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Alabama	38	641	517	123
Arkansas	14	277	203	74
Delaware	5	73	58	15
Florida	27	532	399	133
Illinois	91	1,519	845	675
Indiana	44	894	580	314
Iowa	19	422	309	113
Kansas	31	562	421	140
Kentucky	33	619	407	212
Louisiana	101	2,046	1,467	579
Maryland	18	353	209	144
Michigan	67	1,149	844	304
Mississippi	22	366	343	23
Missouri	13	224	179	45
New Jersey	7	72	11	61
New York	41	685	59	625
Ohio	86	1,476	1,075	402
Oklahoma	40	749	669	81
Pennsylvania	79	1,359	423	936
Tennessee	42	742	514	228
Texas	374	6,444	3,311	3,133
Virginia	30	450	350	100
West Virginia	21	421	334	87
Wisconsin	37	697	471	226
	1280	**22,774**	**14,000**	**8,774**

Attachment 6 – NOx Emission Reductions by Source Group for Sources in the 25 to 100 Ton per Year Reduction Group

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Ammonia - NG-Fired Reformers2	7	200	155	45
Cement Kilns	4	93	0	93
Cement Manufacturing - Wet	2	60	0	60
Ceramic Clay Mfg; Drying	4	29	0	29
Coal Cleaning-Thrml Dryer; Fluidized Bed	10	188	188	0
Comm./Inst. Incinerators	4	47	47	0
Ext Comb Boilers, Elec Gen, Nat Gas (2)	1	28	28	0
Ext Comb Boilers, Elec Gen, Sub/Bit Coal (3)	14	158	158	0
Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	2	9	9	0
Fluid Cat Cracking Units; Cracking Unit	21	393	0	393
Fuel Fired Equip; Furnaces; Natural Gas	3	18	18	0
Fuel Fired Equip; Process Htrs; Pro Gas	7	86	86	0
Gas Turbines - Natural Gas	438	7,193	5,749	1,444
Glass Manufacturing - Flat	8	190	0	190
ICI Boilers - Coal/FBC	1	35	22	13
ICI Boilers - Coal/Stoker	133	2,502	1,629	873
ICI Boilers - Coal/Wall	11	246	246	0
ICI Boilers - Distillate Oil	4	75	0	75
ICI Boilers - Gas	26	601	0	601
ICI Boilers - Natural Gas	350	6,814	3,705	3,109
ICI Boilers - Oil	2	41	0	41
ICI Boilers - Process Gas	31	609	0	609
ICI Boilers - Residual Oil	28	484	437	47

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Indust. Incinerators	21	230	118	113
In-Proc;Process Gas;Coke Oven/Blast Furn	4	33	8	25
Iron & Steel - In-Process Comb - Coal	1	19	0	19
Iron & Steel Mills - Reheating	32	481	481	0
Municipal Waste Combustors	25	472	228	243
Nitric Acid Manufacturing	14	363	289	74
Petroleum Refinery Gas-Fired Process Heaters	30	456	0	456
Solid Waste Disp;Gov;Other Incin;Sludge	1	6	6	0
Space Heaters - Natural Gas	2	17	13	4
Steel Foundries; Heat Treating Furn	7	122	122	0
Surf Coat Oper;Coating Oven Htr;Nat Gas	2	11	0	11
Utility Boiler - Coal/Wall	2	48	48	0
Utility Boiler - Coal/Wall2	1	13	13	0
Utility Boiler - Oil-Gas/Tangential	8	99	62	37
Utility Boiler - Oil-Gas/Wall	19	307	137	170
	1280	**22,774**	**14,000**	**8,774**

Attachment 7 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the 25 to 100 Ton per Year Reduction Group

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
211 Oil and Gas Extraction	146	2,674	2,573	100
212 Mining (except Oil and Gas)	12	247	227	20
213 Support Activities for Mining	1	20	20	0
221 Utilities	96	1,575	1,035	540
311 Food Manufacturing	46	715	450	266
312 Beverage and Tobacco Products	9	151	91	60
313 Textile Mills	1	24	15	9
314 Textile Product Mills	1	12	7	4
316 Leather and Allied Product Manufacturing	1	10	7	3
321 Wood Product Manufacturing	6	100	56	44
322 Paper Manufacturing	79	1,662	1,028	634
324 Petroleum and Coal Products	115	2,083	527	1,556
325 Chemical Manufacturing	332	6,480	3,218	3,262
326 Plastics and Rubber Products	13	206	142	65
327 Nonmetallic Mineral Product Manufacturing	24	417	32	385
331 Primary Metal Manufacturing	87	1,380	1,094	285
332 Fabricated Metal Product Manufacturing	4	80	46	33
333 Machinery Manufacturing	2	20	14	6
334 Computer and Electronic Products	1	9	9	0
336 Transportation Equipment Manufacturing	13	261	192	69
337 Furniture and Related Products	2	18	18	0
447 Gasoline Stations	1	7	0	7
454 Nonstore Retailers	1	9	0	9

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
482 Rail Transportation	3	37	23	14
486 Pipeline Transportation	156	2,551	2,034	517
488 Support Activities for Transportation	1	18	12	6
531 Real Estate	8	147	0	147
541 Professional Services	6	81	77	4
561 Administrative and Support Services	1	8	0	8
562 Waste Mgmt and Remediation Services	21	376	184	192
611 Educational Services	62	963	617	346
622 Hospitals	7	116	36	80
713 Amusement, Gambling, and Recreation	2	49	45	4
721 Accommodation	2	25	10	15
922 Justice, Public Order, and Safety Activities	4	29	17	12
923 Administration of Human Resources	1	12	8	4
928 National Security and International Affairs	13	201	135	66
	1280	**22,774**	**14,000**	**8,774**

Attachment 8 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the 25 to 100 Ton per Year Reduction Group

Recommended Change to CoST Control	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Already Controlled	207	3,380	0	3,380
Already Controlled by Refinery CD	40	704	0	704
Low NOx Burner	362	6,087	6,087	0
Low NOx Burner and Flue Gas Recirculation	361	6,726	4,491	2,235
Low NOx Burner and SCR	11	246	246	0
Low NOx Burner and SNCR	24	437	437	0
Natural Gas Reburn	1	28	28	0
Non-Selective Catalytic Reduction	12	289	289	0
Questions About Feasibility	1	22	0	22
Questions About Feasibility - Cement	6	154	0	154
Questions About Feasibility - Ceramic Clay Mfg	4	29	0	29
Questions about Feasibility - Coating Ovens	2	11	0	11
Questions about Feasibility - Distillate Oil	6	116	0	116
Questions About Feasibility - Glass	7	167	0	167
Questions about Feasibility - Process Gas	50	1,070	0	1,070
Selective Catalytic Reduction	8	216	216	0
Selective Non-Catalytic Reduction	178	3,094	2,207	886
	1280	**22,774**	**14,000**	**8,774**

To: US EPA OAQPS

From: SRA International, Inc.

Subject: Summary of State NOx Regulations for Selected Stationary Sources

Date: September 30, 2014

SRA compiled a summary of state/local NOx emission control regulations pertaining six categories of nonEGUs:

- Cement kilns
- Industrial/Commercial/Institutional (ICI) Boilers – Coal-fired
- ICI Boilers – Gas-fired
- ICI Boilers – Oil-fired
- Gas Turbines
- Internal Combustion (IC) Engines

The analysis included 27 states in the eastern two-thirds of the U.S. For each of these states and source categories, we identified state-specific sub-categories (e.g. fuel type or size threshold), the NOx emission limit or control requirement, averaging time for the emission limit, geographic applicability within the state, testing/monitoring requirements, and rule citation. This information is contained in the attached spreadsheet (Draft State NOx RACT Limits 2014_04_01.xlsx).

Attachment 1 is an overall summary of the relative stringency of the NOx requirements by geographic area and source category. We also prepared a 2-page summary for each of the six categories to concisely compare state NOx emission limits or control requirements. These are shown in Attachments 2 to 7, along with notes highlighting the major differences between the state regulations.

Please let us know should you have questions or comments about any of the data presented in this memorandum.

Attachment 1 – Relative Stringency of NOx Requirements

Source Category	States/Areas with Most Stringent Regulations	States/Areas with Less Stringent Regulations	States with No Regulations or Sources
Cement Kilns[1]	*States*: IL, MD, NY, PA, TX *Areas*: Ellis County, TX	*States*: AL (NOx SIP area), IN, KY, MO, MI, OH, SC, TN, VA, WV	*States*: AR, FL, GA, MS, OK *States with no cement kilns*: CT, DE, LA, MA, NC, NJ, WI
Coal-fired ICI Boilers[2]	*States*: NY *Areas*: Chicago, St. Louis (IL portion), Baton Rouge, Houston-Galveston (coke-fired), Milwaukee,	*States*: FL, GA, IN, MA, MD, MI, PA, TN, VA *Areas*: Chicago, St. Louis (MO portion), Baton Rouge, Charlotte, Cleveland	*States*: AL, AR, KY, MS, OK, SC, TX (except Houston-Galveston) WV *NE States with no coal-fired ICI boilers*: CT, DE, NJ
Gas-fired ICI Boilers	*States*: NJ, NY, PA *Areas*: Chicago, St. Louis (IL portion), Baton Rouge, Beaumont-Port Arthur, Cleveland, Dallas, Houston, Milwaukee	*States*: CT, DE, FL,GA, MA, MD, MI, MO, TN, VA *Areas*: Clark/Floyd Counties, St. Louis (MO portion), Charlotte	*States*: AL, AR, KY, MS, OK, SC, WV
Oil-fired ICI Boilers	*States*: NJ, NY, PA *Areas*: Chicago, St. Louis (IL portion), Baton Rouge, Cleveland, Dallas, Houston, Milwaukee	*States*: CT, DE, FL, GA, MA, MD, MI, TN, VA *Areas*: Clark/Floyd Counties, St. Louis (MO portion), Charlotte	*States*: AL, AR, KY, MS, OK, SC, WV
Gas Turbines	*States*: NJ *Areas*: GA 45-county area, Dallas, Houston, Milwaukee	*States*: CT, DE, FL, LA, MA, MD, NY, PA, TN, VA *Areas*: Chicago, St. Louis (IL portion), St. Louis (MO portion), Charlotte, Cleveland,	*States*: AL, AR, IN, KY, MI, MS, OK, SC, WV
IC Engines > about 500 hp	*States*: MD, NJ, NY *Areas*: Chicago, St. Louis (IL portion), Dallas, Houston	*States*: CT, DE, MA, MI, PA, TN, VA *Areas*: Baton Rouge, St. Louis (MO portion), Charlotte, Cleveland, Milwaukee	*States*: AL, AR, IN, KY, MS, OK, SC, WV

1) Cement kiln emission limits imposed by recent EPA enforcement settlements tend to be more stringent than the emission control requirements in state rules.
2) CT, DE and NJ have no active coal-fired boilers, so the stringency of their regulations for coal-fired ICI boilers is difficult to evaluate

Attachment 2 - Cement Kilns

	NOx Limit (lbs/ton clinker)			
State	**Long Dry**	**Long Wet**	**Pre-heater**	**Pre-calciner**
AL	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
AR	No Limits	No Limits	No Limits	No Limits
CT	No Cement Kilns in State			
DE	No Cement Kilns in State			
FL	No Limits	No Limits	No Limits	No Limits
GA	No Limits	No Limits	No Limits	No Limits
IL	5.1	5.1	3.8	2.8
IN	6.0	5.1	3.8	2.8
IN (Clark/Floyd)	10.8 (op day)/ 6 (30 day)	No Limits	5.9 (op day)/ 4.4 (30 day)	No Limits
KY	6.6	6.6	6.6	6.6
LA	No Cement Kilns in State			
MA	No Cement Kilns in State			
MD	5.1	6.0	2.8	2.8
MI	6.0	5.1	3.8	2.8
MO	6.0	6.8	4.1	2.7
MS	No Limits	No Limits	No Limits	No Limits
NC	No Cement Kilns in State			
NJ	No Cement Kilns in State			
NY	Case-by-case RACT Determination			
OH	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
OK	No Limits	No Limits	No Limits	No Limits
PA	3.44*	3.88*	2.36*	2.36*
SC	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
TN	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
TX	5.1	4	3.8	2.8
TX (Ellis County)	No Limits	3.4	No Limits	1.7
VA	Case-by-case RACT Determination			
WI	No Cement Kilns in State			
WV	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			

ACT = Alternative Control Technology

* Pennsylvania has proposed “RACT 2” presumptive RACT limits

Observations Regarding State NOx Rules for Cement Kilns:

- Geographic Applicability
  - All NOx SIP Call states with cement kilns have NOx rules in place
  - Since only portions of Alabama, Michigan, and Missouri were affected by NOx SIP Call, the NOx rules only apply in the affected counties.
  - States not included in the NOx SIP Call do not have NOx RACT for cement kilns, except for Texas. The Texas NOx requirements only apply in in Bexar, Comal, Ellis, Hays, and McLennan Counties.
- Form of NOx Limitation or Control Requirement
  - A few states express the requirement as “at least one of the following: low-NOx burners, mid-kiln system firing, alternative control techniques or reasonably available control technology approved by the Director and the EPA as achieving at least the same emissions decreases as with low-NOX burners or mid-kiln system firing.”
  - A few states specify presumptive emission limits in terms of pounds of NOx per ton of clinker.
  - Three states do not set presumptive emission limits but rather require facilities to submit a case-by-case RACT determination. Pennsylvania has a proposed regulation that will specify presumptive RACT limits; current rules require sources to hold 1 trading allowance per ton of NOx calculated by multiplying tons clinker by the presumptive NOx limit.
- Stringency of NOx Limitation or Control Requirement
  - For states requiring “low-NOX burners, mid-kiln system firing, or ACT”, it is generally assumed that this will result in a 30% reduction from uncontrolled levels.
  - For states with numerical emission limits, the limits generally represent a 20 – 40 % reduction from uncontrolled levels, depending on the type of kiln.
  - Texas has very stringent limits for kilns in Ellis County.
  - Pennsylvania has proposed presumptive RACT emission limitations in April 2014 that are more stringent than existing presumptive RACT limits in other states.

Attachment 3 – Coal-fired Boilers

		NOx Limit (lbs/mmBtu)		
State	**Geographic Area**	**Boilers 50-100 mmBtu/hr**	**Boilers 100 - 250 mmBtu/hr**	**Boilers >250 mmBtu/hr**
AL	Statewide	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits
CT	Statewide	0.29 to 0.43	0.29 to 0.43	0.29 to 0.43
DE	Statewide	LEA, Low NOx, FGR	0.38 to 0.43	0.38 to 0.43
FL	Broward, Dade, Palm Beach Counties	0.9	0.9	0.9
GA	45 county area	No limits	30 ppmvd @ 3% O2	0.7
IL	Chicago & St Louis areas	Tune-up	0.12 CFB 0.25 Other	0.12 CFB 0.18 Other
IN	Clark and Floyd Counties	No limits	0.4 to 0.5	0.4 to 0.5
KY	Statewide	No limits	No limits	No limits
LA	Baton Rouge 5 counties & Region of Influence	0.2	0.1	0.1
MA	Statewide	0.43	0.33 to 0.45	0.33 to 0.45
MD	Select counties	No limits	0.38 to 1.0	0.38 to 1.0
MI	Fine grid zone	No limits	No limits	0.4
MO	St Louis area	No limits	0.45 to 0.86	0.45 to 0.86
MS	Statewide	No limits	No limits	No limits
NC	Charlotte 6 county area	No limits	0.4 to 0.5	1.8
NJ	Statewide	0.43 to 1.0	0.38 to 1.0	0.38 to 1.0
NY	Statewide	No limits	0.08 to 0.20	0.08 to 0.20
OH	Cleveland 8 county area	0.3	0.3	0.3
OK	Statewide	No limits	No limits	No limits
PA	Statewide	0.45	0.45	0.20 to 0.35
SC	Statewide	No limits	No limits	NOx SIP Call
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT
TX	Houston area	0.057 coke-fired	0.057 coke-fired	0.057 coke-fired
VA	Northern VA	No limits	0.38 to 1.0	0.38 to 1.0
WI	Milwaukee 7 county area	0.10 to 0.25	0.10 to 0.25	0.10 to 0.20
WV	Statewide	No limits	No limits	No limits

Observations Regarding State NOx Rules for Coal-fired Boilers:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Six states (AL, AR, KY, MS, OK, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
  - Texas only has emission limitations for coke-fired boilers in the Houston-Galveston nonattainment area.
- Size Applicability
  - Most of the states do not have NOx emission requirements for boilers less than 100 mmBtu/hour.
  - 10 states do regulation boilers in the 50-100 mmBtu size range.
- Form of NOx Limitation or Control Requirement
  - Nearly all states express the NOx emission limits in terms of lbs/mmBtu.
  - A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NOx burners, flue gas recirculation).
- Stringency of NOx Limitation or Control Requirement
  - Most states specify different emission limits for different types of boilers and firing types (e.g., dry bottom tangential-fired) vs. dry bottom wall-fired)
  - A few states in the Northeast have very few or no coal-fired ICI boilers, so the stringency of the regulations in those states is difficult to evaluate. These states are CT, DE, NJ and MA.
  - For boilers greater than 100 mmBtu/hour, the LADCO/OTC[1] Phase I recommended limits are in the 0.2-0.3 lbs/mmBtu range (depending on boiler/firing configuration). The LADCO/OTC Phase II recommended limits are in the 0.1-0.2 lbs/mmBtu range. Four areas have limits that generally meet the LADCO/OTC recommendations (Chicago, Baton Rouge, New York State, and Milwaukee.
  - Texas has a very stringent limit (0.057 lbs/mmBtu) for coke-fired boilers in the Houston-Galveston area.

[1] *Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers Technical Support Document (TSD), March, 2011* prepared by the Lake Michigan Air Directors Consortium (LADCO) and the Ozone Transport Commission (OTC).

Attachment 4 – Gas-fired Boilers

		NOx Limit (lbs/mmBtu)		
State	**Geographic Area**	**Boilers 50-100 mmBtu/hr**	**Boilers 100 - 250 mmBtu/hr**	**Boilers >250 mmBtu/hr**
AL	Statewide	No Limits	No Limits	No Limits
AR	Statewide	No Limits	No Limits	No Limits
CT	Statewide	0.2 to 0.43	0.2 to 0.43	0.2 to 0.43
DE	Statewide	LEA, low NOx, FGR	0.2	0.2
FL	Broward, Dade, Palm Beach Counties	0.2 to 0.5	0.2 to 0.5	0.2 to 0.5
GA	45 county area	30 ppmvd @ 3% O2	30 ppmvd @ 3% O2	0.2
IL	Chicago & St. Louis Areas	Tune-up	0.08	0.08
IN	Clark and Floyd Counties	No Limits	0.2	0.2
KY	Statewide	No Limits	No Limits	No Limits
LA	Baton Rouge 5 counties & Region of Influence	0.1 to 0.2	0.1	0.1
MA	Statewide	0.1	0.2	0.2 to 0.28
MD	Select counties	Tune-up	0.2	0.2
MI	Fine grid zone	No limits	Source specific RACT	0.2
MO	St Louis area	No limits	0.2 to 0.5	0.2 to 0.5
MS	Statewide	No limits	No limits	No Limits
NC	Charlotte 6 county area	0.3	0.3	0.3
NJ	Statewide	0.1 to 0.5	0.1	0.1
NY	Statewide	0.05	0.06	0.08
OH	Cleveland 8 county area	0.1	0.1	0.1
OK	Statewide	No limits	No limits	No limits
PA	Statewide	0.08	0.08	0.08
SC	Statewide	No limits	No limits	No Limits
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT
TX	Dallas and Houston areas	0.03 or 90% reduction	0.03 or 90% reduction	0.03 or 90% reduction
TX	Beaumont area	0.10	0.10	0.10
VA	Northern VA	0.2	0.2	0.2
WI	Milwaukee 7 county area	No limits	0.08	0.08
WV	Statewide	No limits	No limits	No Limits

Observations Regarding State NOx Rules for Gas-fired Boilers:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Six states (AL, AR, KY, MS, OK, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, TX,VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- Size Applicability
  - About half of the states have NOx emission requirements for boilers less than 100 mmBtu/hour, ranging from combustion tuning to emission limits as low as 0.05 lbs/mmBtu.
- Form of NOx Limitation or Control Requirement
  - Nearly all states express the NOx emission limits in terms of lbs/mmBtu.
  - A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NOx burners, flue gas recirculation).
- Stringency of NOx Limitation or Control Requirement
  - The LADCO/OTC Phase I recommendations are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.1 lbs/mmBtu or 50% reduction for boilers greater than 100 mmBtu/hr.
  - The LADCO/OTC Phase II recommendations are either 0.05-0.1 lbs/mmBtu or 60% reduction.
  - New Jersey and New York have state-wide limits that are consistent with the OTC/LADCO Phase II recommendations. Pennsylvania has proposed state-wide limits that are consistent with the OTC/LADCO Phase II recommendations.
  - Five areas (Chicago, Baton Rouge, Beaumont-Port Arthur, Cleveland, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations.
  - Dallas and Houston have the most stringent emission limitations – 0.02 lbs/mmBtu for greater that 100 mmBtu/hr units.

Attachment 5 – Oil-fired Boilers

		NOx Limit (lbs/mmBtu)		
State	**Geographic Area**	**Boilers 50-100 mmBtu/hr**	**Boilers 100 - 250 mmBtu/hr**	**Boilers >250 mmBtu/hr**
AL	Statewide	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits
CT	Statewide	0.2 Distillate 0.25-0.43 Resid.	0.2 Distillate 0.25-0.43 Resid.	0.2 Distillate 0.25-0.43 Resid.
DE	Statewide	LEA, Low NOx, FGR	0.38 to 0.43	0.38 to 0.43
GA	45 county area	30 ppmvd	30 ppmvd	0.3
IL	Chicago & St Louis areas	Tune-up	0.1 Distillate 0.15 Resid.	0.1 Distillate 0.15 Resid.
IN	Clark and Floyd Counties	No limits	0.2 Distillate 0.3 Resid.	0.2 Distillate 0.3 Resid.
KY	Statewide	No limits	No limits	NOx SIP Call
LA	Baton Rouge	0.2	0.1	0.1
MA	Statewide	Tune-up	0.3 Distillate 0.4 Resid.	0.25 to 0.28
MD	Select counties	No limits	0.25	0.25
MI	Fine grid zone	No limits	No limits	0.3 Distillate 0.4 Residual
MO	St Louis area	No limits	0.3	0.3
MS	Statewide	No limits	No limits	No limits
NC	Charlotte 6 county area	0.2	0.2	0.2
NJ	Statewide	Tune-up	0.1 Distillate 0.2 Resid.	0.1 Distillate 0.2 Resid.
NY	Statewide	0.08 to 0.2	0.15	0.15 to 0.2
OH	Cleveland 8 county area	0.12 Distillate 0.23 Resid.	0.12 Distillate 0.23 Resid.	0.12 Distillate 0.23 Resid.
OK	Statewide	New only	New only	New only
PA	Statewide	0.12 Distillate 0.20 Resid.	0.12 Distillate 0.20 Resid.	0.12 Distillate 0.20 Resid.
SC	Statewide	No limits	No limits	No limits
TN	5 Counties	Case-by-Case RACT	Case-by-Case RACT	Case-by-Case RACT
TX	Dallas and Houston areas	No limits	~0.01	~0.01
VA	Northern VA	0.25 to 0.43	0.25 to 0.43	0.25 to 0.43
WI	Milwaukee 7 county area	No limits	0.10 Distillate 0.15 Resid.	0.10 Distillate 0.15 Resid.
WV	Statewide	No limits	No limits	No limits

Observations Regarding State NOx Rules for Oil-fired Boilers:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Six states (AL, AR, MS, OK, SC, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, TX, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- Size Applicability
  - About half of the states have NOx emission requirements for boilers less than 100 mmBtu/hour, ranging from combustion tuning to emission limits as low as 0.08 lbs/mmBtu.
- Form of NOx Limitation or Control Requirement
  - Nearly all states express the NOx emission limits in terms of lbs/mmBtu.
  - A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NOx burners, flue gas recirculation).
- Stringency of NOx Limitation or Control Requirement
  - The LADCO/OTC Phase I recommendations for distillate oil are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.1 lbs/mmBtu or 50% reduction for boilers greater than 100 mmBtu/hr. The LADCO/OTC Phase II recommendations for distillate oil are either 0.08-0.1 lbs/mmBtu or 60% reduction.
  - Only New Jersey has state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for distillate oil.
  - Three areas (Chicago, Baton Rouge, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations for distillate oil.
  - The LADCO/OTC Phase I recommendations for residual oil are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.2 lbs/mmBtu or 60% reduction for boilers greater than 100 mmBtu/hr. The LADCO/OTC Phase II recommendations for residual oil are either 0.2 lbs/mmBtu or 50-70% reduction.
  - New Jersey and New York have state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil. Pennsylvania has proposed state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil.
  - Four areas (Chicago, Baton Rouge, Charlotte, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil
  - Dallas and Houston have the most stringent emission limitations – 0.01 lbs/mmBtu for greater that 100 mmBtu/hr units.

Attachment 6 – Gas Turbines

		NOx Limit (ppmvd @15% O2)			
State	**Geographic Area**	**Simple Cycle >25 MW Gas-fired**	**Simple Cycle >25 MW Oil-fired**	**Combined Cycle > 25 MW Gas-fired**	**Combined Cycle > 25 MW Oil-fired**
AL	Fine grid zone	No limits	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits	No limits
CT	Statewide	55	258 (0.9 lb/mmBtu)	55	258 (0.9 lb/mmBtu)
DE	Statewide	42	88	42	88
GA	45 county area	6	6	6	6
IL	Chicago & St Louis areas	42	96	42	96
IN	Statewide	No limits	No limits	No limits	No limits
KY	Statewide	No limits	No limits	No limits	No limits
LA	Baton Rouge 5 counties & Region of Influence	54 (0.2 lb/mmBtu)	86 (0.3 lb/mmBtu)	54 (0.2 lb/mmBtu)	86 (0.3 lb/mmBtu)
MA	Statewide	65	100	42	65
MD	Select counties	42	65	42	65
MI	Fine grid zone	No limits	No limits	No limits	No limits
MO	St Louis area	75	100	75	100
MS	Statewide	No limits	No limits	No limits	No limits
NC	Charlotte 6 county area	75	95	75	95
NJ	Statewide	33 (2.2 lb/MWh)	53 (3.0 lb/MWh)	33 (2.2 lb/MWh)	53 (3.0 lb/MWh)
NY	Statewide	50	100	42	65
OH	Cleveland 8 county area	42	96	42	96
OK	Statewide	No limits	No limits	No limits	No limits
PA	Statewide	42	75	42	75
SC	Statewide	No limits	No limits	No limits	No limits
TN	5 Counties	source specific RACT	source specific RACT	source specific RACT	source specific RACT
TX	Dallas and Houston areas	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)
VA	Northern VA	42	65/77	42	65/77
WI	Milwaukee 7 county area	25 to 42	65 to 96	9	9
WV	Statewide	No limits	No limits	No limits	No limits

Appendix B

Observations Regarding State NOx Rules for Gas Turbines:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Nine states (AL, AR, IN, KY, MI, MS, OK, SC, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (GA, IL, LA, MO, NC, OH, TN, TX, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- Other Applicability Criteria
  - States use a variety size thresholds. For example, Ohio's rules differentiate between units < 3.5 MW and > 3.5 MW. Wisconsin has requirements for three size ranges: 10-25 MW, 25-50 MW, and >50 MW.
  - State limits generally differ by type of fuel – gas or oil. Wisconsin also includes limits for biologically derived fuel.
  - Some states have different limits for simple-cycle and combined-cycle units. Other states have a single limit that applies to both types of units.
- Form of NOx Limitation or Control Requirement
  - States do not specify specific types of control techniques, but rather set a numerical emission limit.
  - Most states express limits in terms of "ppmv at 15% oxygen". Some states use lbs/mmBtu, and the equivalent limits shown in the table above were calculated using based on Part 75 Eq-F5 and F-factors. New Jersey's limits are in terms of lbs/MHr.
- Stringency of NOx Limitation or Control Requirement
  - Three areas have very low limits compared to other states/areas: the 45 county area in Georgia, Dallas and Houston-Galveston

Attachment 7 – IC Engines Greater than ~500 hp

		NOx Limit (g/hp-hr)			
State	**Geographic Area**	**Gas-fired, Lean Burn**	**Gas-fired, Rich Burn**	**Diesel**	**Dual Fuel**
AL	Fine grid zone	No limits	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits	No limits
CT	Statewide	2.5	2.5	8.0	8.0
DE	Statewide	Technology Stds.	Technology Stds.	Technology Stds.	Technology Stds.
GA	45 county area	?	?	?	?
IL	Chicago & St Louis areas	210 ppmvd @ 15% O2 (2.9 g/hp-hr)	150 ppmvd @ 15% O2 (2.2 g/hp-hr)	660 ppmvd @ 15% O2 (9.1 g/hp-hr)	660 ppmvd @ 15% O2 (9.1 g/hp-hr)
IN	Statewide	No limits	No limits	No limits	No limits
KY	Statewide	No limits	No limits	No limits	No limits
LA	Baton Rouge 5 counties & ROI	4.0	2.0	?	?
MA	Statewide	3.0	1.5	9.0	9.0
MD	Select counties	150 ppmvd @ 15% O2 (1.7 g/hp-hr)	110 ppmvd @ 15% O2 (1.6 g/hp-hr)	175 ppmvd @ 15% O2 (2.0 g/hp-hr)	125 ppmvd @ 15% O2 (1.4 g/hp-hr)
MI	Fine grid zone	3.0	1.5	2.3	1.5
MO	St Louis area	3.0 10.0	2.5 to 9.5	2.5 - 8.5	2.5 - 6.0
MS	Statewide	No limits	No limits	No limits	No limits
NC	Charlotte Area	2.5	2.5	8.0	8.0
NJ	Statewide	2.5	1.5	8.0	8.0
NY	Statewide	1.5	1.5	2.3	2.3
OH	Cleveland	3.0	3.0	3.0	3.0
OK	Statewide	No limits	No limits	No limits	No limits
PA	Statewide	3.0	2.0	8.0	8.0
SC	Statewide	No limits	No limits	No limits	No limits
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT	Source specific RACT
TX	Dallas and Houston area	0.5	0.5	2.8 to 6.9	0.5
VA	Northern VA	Source specific RACT	Source specific RACT	Source specific RACT	Source specific RACT
WI	Milwaukee 7 county area	3.0	3.0	3.0	3.0
WV	Statewide	No limits	No limits	No limits	No limits

Observations Regarding State NOx Rules for IC Engines:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Eight states (AL, AR, IN, KY, MS, OK, SC, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (GA, IL, LA, MI, MO, NC, OH, TN, TX, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- Other Applicability Criteria
  - States use a variety size thresholds. For example, Louisiana's rules have separate limits for IC engines that are 150-300 hp, >300 hp, and >1500 hp. New York uses > 200 hp and > 400 hp. Delaware uses > 450 hp, while North Carolina uses > 650 hp.
  - State limits generally differ by type of fuel – gas, oil, dual-fuel or landfill/digester gas.
  - A few states have different limits lean-burn and rich-burn engines. Other states have a single limit that applies to both types of units.
- Form of NOx Limitation or Control Requirement
  - Most states express limits in terms of "gram per brake horsepower hour".
  - Some states use "ppmvd @ 15% O2", and the equivalent limits shown in the table above were calculated using conversion factors from ppmv @ 15% O2 to g/hp-hr from EPA ACT, July 1993 EPA453-R-93-032.
  - Delaware specifies control technology standards rather than numerical emission limits.
- Stringency of NOx Limitation or Control Requirement
  - Maryland, New Jersey, New York and the Dallas/Houston areas of Texas have limits that are more stringent than other states/areas.