Appendix 1

GUIDANCE DOCUMENT ON REASONABLY AVAILABLE CONTROL TECHNOLOGY FOR SOURCES OF NOx EMISSIONS

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INTRODUCTION:

Pennsylvania's regulation, Title 25, Environmental Resources, Article III, Chapter 129, Standards for Sources, Section 129.91, requires Reasonably Available Control Technology (RACT) to be determined on a case-by-case basis for major sources or facilities. RACT is defined as: The lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.

Presumptive RACT standards have been established in Section 129.93 for certain select source categories. In many states, presumptive standards are the norm with emission limitations or technologies established for most major categories. However, because Pennsylvania has more sources with a greater degree of diversity, the case-by-case RACT process is preferred.

This document is therefore intended to provide guidance and information needed to examine the case-by-case RACT determinations for the affected sources or facilities. In cases where the regulations have provided presumptive RACT, further details on the rationale for the presumptive standards will be given.

Section I contains a general discussion of the Clean Air Act Amendments (CAAA) and how it affects the Commonwealth. A discussion on the NOx emission inventory is included. Section II describes the RACT submittal process and the subsequent case-by-case NOx RACT determination procedures. Section III contains the criteria for allowing emission averaging. Section IV includes the guidance on the establishment of final RACT limitations using actual emission data.

Attachment 1 provides a general summary of various NOx control strategies, followed by a series of Modules which describe in detail the application of NOx RACT for various source categories. The modules are compilation of available information on these source categories. Depending upon the need, specific Modules may be requested by the interested parties. The Modules available are as follows:

- Module 1- Utility Boilers and Boilers >= 100 MMBtu/hr
- Module 2- Industrial, Commercial, Institutional boilers <100 MMBtu/hr
- Module 3- Internal Combustion Engines
- Module 4- Turbines
- Module 5- Glass Furnaces
- Module 6- Process Heaters
- Module 7- Iron and Steel Mills
- Module 8- Cement Manufacturing
- Module 9- Miscellaneous and Presumptive RACT Sources

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I. GENERAL DISCUSSION:

The Clean Air Act Amendments (CAAA) of 1990 require Pennsylvania to meet the health-related, ground level ozone National Ambient Air Quality Standard (NAAQS). In the presence of sunlight, oxides of nitrogen (NOx), and volatile organic compounds (VOC) react to form ground level ozone. Ozone is a known respiratory irritant, and may significantly reduce the yield of important food crops. Ozone may also cause degradation of paint, plastics, textiles and rubber. NOx is also a precursor to acid deposition. NOx, in the form of Nitrogen Dioxide, (NO_2) is known to aggravate symptoms associated with asthma and bronchitis. NO_2 can also increase susceptibility to respiratory infections. Ground level ozone should not be confused with stratospheric ozone which is beneficial and needed in the upper levels of the atmosphere to block harmful radiation from the sun.

Attaining the ozone air quality standard is a statewide problem for Pennsylvania. A number of counties are classified as nonattainment for not meeting the NAAQS. The CAAA created a special classification system of ozone nonattainment areas depending on the severity of the ozone levels within a consolidated metropolitan statistical area (CSMA). Figure 1 shows these classifications for Pennsylvania. Some counties are classified as nonattainment but are not part of a CMSA.

The five-county Pennsylvania portion of the Philadelphia CSMA is classified as a severe area. In fact, there are serious region-wide violations of the ozone standard throughout the entire northeastern United States. The CAAA address this problem of regional nonattainment through the establishment of the Ozone Transport Region (OTR), of which Pennsylvania has been designated as one of its 13 states or political entities. At a minimum, this action requires that any major VOC or NOx source in the entire state of Pennsylvania is subject to the requirements that apply to major sources in ozone areas classified as moderate, even though some Pennsylvania counties are achieving the NAAQS attainment levels. The major sources located in the Philadelphia Metropolitan Statistical Area are subject to the requirements of severe ozone nonattainment area.

The CAAA require areas which exceed NAAQS for ozone to implement NOx RACT programs for all major NOx facilities. The RACT programs are to apply to all facilities which emit or have the potential to emit greater than 100 tons per year of NOx. In the case of severe nonattainment areas such as the five-county Pennsylvania portion of Philadelphia CSMA facilities of greater than 25 tons per year of NOx are subject to RACT requirements.

Regarding the applicability, if the facility's "potential to emit" was above the RACT threshold (e.g 100 TPY) but the actual emissions for the year 1990 calendar year and for the subsequent years were below the threshold, the facility has the option to accept a federally enforceable condition to limit the emissions to be under the applicability

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threshold. Such a condition would make the facility "synthetic minor" and would not be subject RACT requirements. Since the Pennsylvania's operating permit is not currently federally enforceable, the permit amendment with such conditions must be incorporated in to Pa's SIP as revisions in order to make them federally enforceable.

On the other hand, if the facility's actual emissions for the calendar year 1990 were above the RACT applicability threshold, the facility could never be made "synthetic minor" even if the facility is willing to limit the emissions in the future. Thus such facility would be subject to the RACT.

NOx Emissions Distribution By Source

Statewide, mobile sources make up 31% of the total NOx emissions. The remaining 69% comes from stationary sources. Of the latter, the utility industry accounts for 80% of the total NOx emissions. Natural gas transmission accounts for 5% of the total stationary source NOx emissions while the remaining 15% of NOx is derived from miscellaneous sources. Of these miscellaneous sources, glass manufacturing accounts for slightly greater than 1% of the total NOx emissions and asphalt plants less than 1% of the total. Other industries include miscellaneous utilities at 1%, metallurgical at 3%, chemical industry at less than 1%, refining at 2%, mineral industry at 3%, and all other sources at 5%. (See Figure 2 and Table 1) This information was extracted from Pennsylvania Emission Data System (PEDS). Due to thresholds established for including in the PEDS, all the sources in some source categories such as asphalt plants were not included in the PEDS.

The proposed NOx RACT standards are mandated for the ozone non-attainment areas and are part of the strategy to bring Pennsylvania into attainment of the NAAQS for ozone. Due to the implementation of RACT we anticipate the NOx emissions from stationary sources to be reduced by about 35-40 percent.

Preliminary emissions modeling via ROMNET indicates that the first stage RACT reductions may not be sufficient to achieve NAAQS by the stipulated deadlines. Therefore, additional emission reductions may be necessary to achieve attainment of ozone standard in Pennsylvania.

Other states are in various stages of developing their NOx RACT. A summary of their regulations may be found in Table 2 at the end of this document.

II. GUIDANCE FOR SUBMITTING RACT PROPOSALS FOR MAJOR NOX SOURCES:

The final regulation does establish presumptive RACT requirements for three major classes of NOx emitters. For certain small combustion units and certain other classes of fossil fuel burning equipment, presumptive RACT is determined to be the operation of the sources in accordance with the manufacturer's specifications. For certain larger combustion units, RACT is specified to be an annual tune-up and combustion adjustments to provide for low-NOx emitting operation. For very large coal fired combustion units, presumptive RACT is specified to be a low-NOx burner system with separate overfire air.

Although presumptive RACT requirements are contained in the final regulation for certain NOx sources, a source operator may elect to use a case-by-case analysis to establish RACT requirements.

Facilities which are subject to RACT are required to identify themselves within four months of the date of publication of the final regulations in the Pennsylvania Bulletin. These facilities are required to submit a written proposal for RACT for each source to the Department and EPA within six months of adoption of the regulations. All affected facilities must be in compliance with the NOx RACT regulations by May 31, 1995. This deadline is mandated by the CAAA. Therefore, the owner or operator of a source or facility for which RACT is required must obtain approval for a RACT proposal and implement it by May 31, 1995.

Implementing the plan includes obtaining the required permits, installing the approved NOx control, implementing process changes, and complying with all emission limits established by the Department. An owner or operator seeking a RACT determination, and installing an air pollution control device must also submit an application for a Plan Approval, as specified in Chapter 127.

Because the date of RACT implementation is fixed and not dependent upon intermediate events or other regulation promulgation, some facilities may be tempted to initiate control/process changes in the name of RACT without proper permitting. These industries run the risk of wasting money and time on projects which will not pass the review process. Therefore, facilities should obtain approval prior to proceeding with the implementation of the plan.

The case-by-case RACT determinations will require EPA approval as SIP revisions. The Department will coordinate its review of RACT proposals with EPA. The Department will expedite the SIP hearing and submission to assure EPA action as early as possible. After EPA's approval of the RACT regulation, the RACT program which implements the presumptive RACT requirements will not require SIP approval. Sources meeting the presumptive levels contained in the regulation do not have to prepare an alternative analysis identifying and evaluating different control scenarios.

Presumptive RACT requirements for oil/gas fired combustion units

It was brought to the Department's attention that the language in the regulation (§ 129.93 (b) (4) could be interpreted as the only presumptive RACT requirement for oil, gas and combination oil/gas fired units irrespective of heat input is recordkeeping. As indicated in the

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background material provided to EQB, the Department's intent was for the oil/gas fired units with rated heat inputs greater than 50 million Btu per hour to be handled through the case-by-case process. The record keeping requirement was intended to be applicable to the oil/gas fired units with rated heat inputs equal to or greater than 20 million Btu per hour. The regulation should be read as follows:

§129.93 (b) (4) (Add the underlined language)
(4) For oil, gas and combination oil/gas units <u>subject to subsection (2),</u> the owner and operator shall maintain records including a certification from the fuel supplier of the type of fuel and for each shipment of distillate oils number 1 or 2, a certification that the fuel complies with ASTM D396-78 "Standard Specifications for Fuel Oils". For residual oils minimum recordkeeping includes a certification from the fuel supplier, of the nitrogen content of the fuel, and identification of the sampling method and sampling protocol.

The Department is planning to clarify the intent of Section 129.93 (b) (4) through an amendment to the regulation. **Content of RACT Proposal:**

The RACT proposal shall include at a minimum:

1) A list of each unit subject to the NOx RACT regulations;

2) The size or capacity of each affected unit and the types of fuel or fuels combusted in each unit;

3) A complete description of each source;

4) Estimated NOx emissions and associated support documents;

5) RACT analysis including technical and economic support documentation for each affected source;

6) A schedule for the implementation of RACT including provisions for demonstrating periodic increments of progress and compliance with RACT

7) The testing, monitoring, record keeping and reporting procedures to be used to demonstrate compliance with RACT.

8) Additional information requested by the Department that is deemed necessary for the determination of RACT.

Guidance for the Case-by-Case RACT analysis:

RACT is defined as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.

The RACT analysis must include a ranking of all applicable and available control technologies for the affected source in descending order of control effectiveness. The applicant first examines the most stringent or "top" alternative. If it can be shown that this level of control is technically or economically infeasible for the source under review, then the next most stringent level of control is determined and similarly evaluated. The analysis continues until the RACT level under consideration cannot be eliminated by any substantial or unique technical or economic objection.

Step-by-step summary of the RACT analysis process:

STEP 1 : Identify all applicable control technologies

The first step is to identify for each affected source all applicable and available control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the source. Air pollution control technologies and techniques include the application of production process or methods, control systems, and the fuel combustion techniques for the control of NOx. The control technologies shall include not only existing controls for the source category, but also technology transfer controls applied to similar source categories.

STEP 2: Eliminate technically infeasible options

In the second step, the technical feasibility of the available control options identified in Step 1 is to be evaluated with respect to the source-specific factors. A demonstration of technical infeasibility should be clearly documented based on physical, or chemical and engineering principles, that technical difficulties would preclude the successful use of the control option on the affected source.

Technically infeasible control options are then eliminated from further consideration in the RACT analysis.

Availability of Technically Feasible options: If a technically feasible option cannot be implemented by May 31, 1995 due to temporary inability (for example, manufacturer's inability to supply the equipment on required schedule) such a option cannot be eliminated from RACT consideration. This issue will be dealt as an enforcement issue rather than a RACT determination issue.

STEP 3: Rank remaining control technologies by control effectiveness

In step 3, all remaining control options not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the NOx emissions. The list should present the array of control options and should include as a minimum the following information:

1) Baseline (before RACT) emissions

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2) control efficiencies

3) expected emissions after the application of the control option
4) economic impacts (both overall cost effectiveness and incremental cost effectiveness)

However, if the proposal selects the top control option the detailed cost analysis is not needed.

Cost-effectiveness:

Cost-effectiveness, in terms of dollars per ton of NOx emissions reduction, is the key criterion to be used in assessing the economic feasibility of a control option. In the economic impacts analysis, primary consideration should be given to quantifying the cost of control and not the economic situation of the affected facility. By expressing costs in terms of the amount of emission reduction achieved, comparisons can be more readily performed among the same type of sources for different facilities.

The cost-effectiveness calculations can be conducted on an average or incremental basis. Average cost-effectiveness is calculated as the annualized cost of the control option being considered divided by the baseline emissions minus the control option emission rate, as shown by the following formula:

Average cost effectiveness (\$/ton removed) =

$$\frac{\text{Control option annualized cost (\$/yr)}}{\text{Baseline emission rate - Control option rate (tons/yr)}}$$

The average cost-effectiveness is also referred to as overall or total cost effectiveness.

The baseline emissions rate represents the maximum emissions before the application of the RACT. It should be calculated using either continuous emission monitoring data (CEM), test results or approved emission factors and historic operating data.

The incremental cost effectiveness calculation compares the costs and emission level of a control option to those of the next most stringent option as shown in the following formula:

Incremental Cost (dollars per incremental ton removed) =

$$\frac{\text{Total cost (annualized) of control option - Total cost (annualized) of next option}}{\text{Next control option emission rate - control emission rate}}$$

Incremental cost-effectiveness comparisons should focus on annualized cost and mission reduction differences between dominant control options.

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The incremental cost-effectiveness should be examined in conjunction with the total cost effectiveness in order to justify elimination of a control option. The primary focus will be on the total cost effectiveness.

For the cost estimates to be used in the economic analysis the data supplied by an equipment vendor (i.e., budget estimates or bids) must be used as much as possible. The basis of the estimates must be thoroughly documented in the RACT analysis. The cost analysis must be consistent with OAQPS Control Cost Manual, (Fourth Edition), EPA 450/3-90-006, January 1990 or as revised.

STEP 4 : Selection of RACT

The Department will generally consider the control option to be cost effective if the total cost effectiveness is no greater than $1500 per ton of NOx reduced.

In addition to the average cost effectiveness of $1500/ton, other factors such as the incremental cost effectiveness and other environmental impacts will also be considered in the RACT determination. For example, a control option with average cost effectiveness less than $1500/ton would not be automatically considered as a RACT option if it causes significant adverse impact on the other media. The adverse side effects of each control option must be factored in the RACT determination process.

We should caution that US EPA Region III has stated that establishing **any** dollar figure in RACT guidance will not provide for an "automatic" selection or rejection of a control technology or emission limitation as RACT for a source or source category. We also understand that EPA headquarters is planning to finalize a guidance document on cost effectiveness for NOx RACT analysis. The document will suggest that a cost effectiveness of up to $2,500 is reasonable.

Rationale for selection of cost effectiveness criteria:

It should be noted that in Pennsylvania the number of affected sources and the types of sources are substantially greater than most of the states in Ozone Transport Region (OTR). Also, the baseline emissions of these sources vary widely. Thus, there is a need for a case-by-case RACT determination as opposed to one set of presumptive limits. While it is appropriate to establish site specific limits the degree of control must be comparable to the other states in OTR.

We applied the following criteria in establishing the cost-effectiveness level. First, the cost of control should be fair and equitable to all. Second, the acceptable control costs should be comparable to costs required to employ the presumptive technology requirements for the large coal fired boilers. Third, the cost effectiveness should be reasonable when compared to the acceptable costs

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established in the existing permitting or regulatory process such as the acceptable costs for BACT determination for new NOx sources and control cost for sources of volatile organic compounds (the other major ozone precursor) to comply with existing RACT regulations based on EPA's guidelines. Finally, the cost-effectiveness should be comparable to that established in other states in the OTR.

The presumptive RACT requirements included in our regulations for coal-fired combustion units with a rated heat input equal to or greater than 100 million Btus per hour, are the installation and operation of low-Nox burners with separated overfire air (LNB-SOFA). As per EPA document "Evaluation and Costing of NOx Controls for Existing Utility Boilers in the NESCAUM Region", the control costs for LNB-SOFA vary from $270 to $1,590 per ton of NOx removed depending on site specific factors (such as the type of boiler, size of the boiler and the amount of utilization). The control measures available to achieve the levels established as presumptive RACT for utility boilers by other states show a range of cost-effectiveness from about $570-$1500 per ton. In fact, two NOx RACT proposals using LNB-SOFA have documented cost of $1,222 and $1,298 per ton.

Therefore, we decided to apply an target limit of one level to all source categories and the level will be set at $1500 per ton.

The Department suggests using $1,500 because it is comparable, but, lower than the control cost for sources of volatile organic compounds (the other major ozone precursor)to comply with existing RACT regulations based on EPA's guidelines. For volatile organic compounds, required controls for existing sources are estimated to cost as much as $3,000 per ton removed.

Also, the cost of presumptive RACT emission limitations for utility boilers in other states have been estimated as $570 to $1,500. Finally, the costs to comply with the presumptive NOx RACT emission levels for other sources in other states is as much as $2,000 per ton removed. It should be noted for BACT determination for NOx emission sources the acceptable cost effectiveness have been as much as $4,000.

In addition to the average cost effectiveness of $1500/ton, the other factors such as the incremental cost effectiveness and other environmental impacts will also be considered in the RACT determination.

Therefore, the use of $1,500 as a target value for one of criteria in the determination of RACT is reasonable.

STEP 5 : Establishment of RACT Emission Limit

If enough uncertainty exists in establishing a final RACT emission limit with the control option chosen by the above procedure, the Department may establish a never-to-exceed preliminary emission limit. The preliminary emission limits for the electric utilities must generally not be less stringent than the emission limits recommended in the EPA's preliminary presumptive RACT levels for electric utility boilers. The final limit is established after adequate actual data is collected with the application of approved technology. The presumptive RACT technology for the coal-fired units with a heat input greater than or equal to 100 Million BTU per hour is "low-NOx burner with a separate OFA". The final limit will be established prior to issuing an operating permit based on the CEM or predictive modeling system or periodic stack test results. In the case of combustion units with a heat input greater than or equal to 250 Million BTU per hour, only a Department-approved CEM system is acceptable for the establishment of the final limit. The CEM system is intended to be any system which meets the performance specification included in the Department's Continuous Source Monitoring Manual. In the case of combustion units with a heat input greater than 100 Million BTU per hour but less than 250 Million BTU per hour source test results may be used in the establishment of limits and the compliance with such limit will be based on the average of three consecutive test runs. A periodic source testing will be required for the verification of the limit. As a minimum, the source testing will be required on annual basis. As the emission data base is established and the data consistently show compliance by a significant margin the testing frequency may be altered. However, the source owner/operator may opt for a predictive modeling program or a CEM system in lieu of periodic testing. The predictive modeling system shall identify and correlate various operating parameters with NOx emission levels through source testing. This predictive modeling program must be approved by the Department. The final limit will be set based upon the available data with an adequate margin for the normal fluctuation of emission levels. The averaging period is generally limited to a 24-hour average in order to protect the hourly ozone standard. Especially for larger sources, a daily averaging may be necessary to accommodate the normal fluctuations of the emission levels. However, the Department may establish a 30-day rolling average in addition to a daily average. The 30-day rolling average may be used to calculate annual baseline emissions for future offset generation. In certain cases the Department may accept the averaging period of 24-hour during the ozone season and a 30 day averaging period during the non-ozone season provided a satisfactory technical/economic justification was made. For the purpose of RACT compliance, the ozone season is defined as the period between April 1 to October 31. The detailed procedure can be found in section IV of this document.

Guidance for coal-fired units proposing to employ the presumptive RACT

For coal-fired combustion units with a rated heat input equal to or greater than 100 million Btus per hour, presumptive RACT requirements are the installation and operation of low-Nox burners with separated overfire air. A low-NOx burner with separated overfire air is defined as a burner design capable of reducing the formation of oxides of nitrogen (NOx) emissions through sub-stoichiometric combustion of fuel by means of a burner assembly consisting of two or more stages and the addition of

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secondary combustion air introduced downstream of the burner location. It is intended that the system be designed to employ the highest degree of staging practicable.

For example, in the case of a tangentially fired (T-fired) combustion unit proposing ABB's Low-NOx Concentric Firing System (LNCFS), presumptive RACT technology is the LNCFS III version unless it is shown that LNCFS III is not feasible either technically or economically. If a LNCFS system or an equivalent low-NOx burner with a SOFA, is proposed as RACT for a T-fired unit the RACT analysis need not address the feasibility of post combustion technologies. However, if LNCFS III is not proposed as RACT the RACT analysis must demonstrate satisfactorily that LNCFS III is not feasible.

Procedure to generate Emission Reduction Credits:

Emission reduction credit (ERC) is defined as a permanent, enforceable, quantifiable and specific reduction which can be considered as a reduction for the purpose of offsetting increases.

"Surplus" emission reductions are reductions not otherwise required by the applicable state implementation plan (SIP) and not already relied upon for SIP planning purposes, and not used by the source to meet any other regulatory requirements. Thus, emission reductions necessary to meet RACT or other statutory requirements such as acid rain limitations are not considered surplus and may not be creditable for emission offsets. In order for NOx emission reductions to be creditable, a federally enforceable RACT determination must have been made. Any reduction beyond the reductions required by RACT is eligible as surplus and thus available for netting or ERC banking purposes. As stated earlier RACT is defined as the lowest emission limitation that a particular source is capable of meeting by application of a control technology that is reasonably available. Therefore, "surplus" cannot be created with the approved RACT control option by merely achieving a lower emission level than the final limit without implementing additional control measures (not including the measures needed to optimize the selected RACT control option) or curtailment of operation. The "surplus" reductions can be achieved by any method, including curtailment of operation (operational limitation, production limits), improved control technologies or measures, shutdown or some combination thereof.

The following procedures will be followed to quantify creditable ERC's generated through the installation of control measures which are determined by the Department to be clearly more stringent than the RACT requirements. The emission reductions achieved via this "overcontrol" must necessarily be greater than reductions that would reasonably be expected from RACT measures.

1. The initial and most important task is to determine the appropriate RACT control technology and estimated emission level reflecting the application of the chosen RACT technology. The Department will use the available technical information in defining this technology and estimating

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the corresponding emission levels. RACT level will be the lowest emission limitation that a particular source is capable of meeting by application of a control technology that is reasonably available. It is also important that these estimated emission levels accurately reflect the maximum degree of control achieved or capable of achievement by similar sources that actually employ similar controls as RACT.

2. After the installation and emission testing of the "overcontrol" technology and establishment of the final NOx emission limit, the comparison will be made between this final emission limit achieved through "overcontrol" and the emission level previously determined for the Department-approved RACT control system. The difference between these two emission rates will be the emission rate used with the fuel consumption data to calculate creditable emission reductions.

3. If an applicant wishes to bank the ERCs due to "overcontrol" prior to installation of "overcontrol" technology, a federally enforceable NOx emission limit reflecting the "overcontrol" will be included in the plan approval. The difference between the NOx limit and the emission level previously determined for the Department-approved RACT control system will be the emission rate used with the fuel consumption data to calculate creditable emission reductions.

It should be noted that the new source which intends to use the ERCs created by the "overcontrol" of this existing source cannot commence operation until the successful implementation of the "overcontrol" technology.

Example: A utility might opt to install an SCR system in lieu of the presumptive RACT technology of LNB-SOFA system on a tangentially-fired boiler with a baseline emission rate of 0.80lb NOx/MMBtu. The existing data on LNB-SOFA on T-fired boilers indicate that up to 50% emission reduction could be achieved by this system. Therefore the the projected emission level after the application of RACT technology is 0.40lb NOx/MMBtu. After the SCR retrofit, the unit achieves an emission rate of 0.13 lb NOx/MMBtu. The difference between 0.40 and 0.13 or 0.27 lb NOx/MMBtu is the rate used with the fuel analysis and consumption data to calculate the creditable NOx ERC's.

III. NOx EMISSION AVERAGING FOR RACT COMPLIANCE:

The Department may approve emission averaging among facilities to provide flexibility in complying with the RACT requirements provided the following criteria are met:

1) The NOx emission reductions achieved through the RACT averaging plan must be no less than the emission reductions that would be achieved by complying with the RACT requirement on a source specific basis.

2) The averaging program shall include a tons per year emission

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cap for each facility that in the aggregate is less than the aggregate of the emissions that would occur from each facility complying individually. In addition, each source shall have an emission rate limit such as lb/mmBTU to provide for independent verification and enforcement of the averaging program.

3) No credit shall be given for emission reductions that are achieved through the shutdown or curtailment of an operation included in the averaging program.

4) The ambient impact from the averaging program must be less than or equivalent to the impact from each source complying individually. This equivalence must be demonstrated both spatially and temporally.

5) The averaging program must be approved as a SIP revision prior to becoming effective.

6) The sources involved in the averaging program shall be required to continuously monitor and record the emissions. In addition the participating facilities are required to establish telemetry links between the facilities to provide real time emission data to all facilities affected by the averaging. For an averaging proposal involving sources at a single facility, the Department may approve alternate requirements provided the proposal demonstrates that the alternate methodologies are credible, workable, replicable and fully enforceable and adequately quantify emissions from all sources participating in the averaging program.

7) The emission averaging programs must be subject to an adequate enforcement mechanism. All the parties involved in the averaging should be held responsible for exceedances of the final RACT requirements.

Emission Averaging:

The emission averaging program may allow some emission sources to emit at a rate that is higher than the RACT rate (which was determined on a case-by-basis) as long as there is a compensating population of emission sources emitting at a rate that is lower than the RACT emission limitation. The allowable emission rate is proportional to the production level. The aggregate of actual emissions from the sources participating in the program must not exceed the aggregate of allowable emissions of those sources.

Air Quality Equivalence:

Traditionally, demonstrations of air quality equivalence required modeling. The modeling demonstrations may be waived, if:

1) the credit generating source in the averaging plan is located in an area with an equal or higher non-attainment designation than the credit consuming source; or,

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2) all sources included in the averaging plan are located within the attainment areas and located in the same broad vicinity; or,

3) all the sources included in the averaging plan are located within the same non-attainment area.

4) all the sources included in the averaging proposal which are not located within the same nonattainment area but are located less than 200 kilometers from any other source involved in the averaging proposal.

Step-by-Step Procedure:

1) Identify the RACT allowable emission levels for each source participating in the averaging plan through case-by-case analysis.

2) The Department sets an allowable source-specific emission rate for each source so that the following equation is met for the maximum allowable averaging period of 24 hours.

$$\Sigma_{i=1-N} \text{ (Case-by-case RACT Allowable ER}_i\text{) x (Projected Activity Level}_i\text{)} \geq \Sigma_{i=1-N} \text{ (Source Specific Allowable ER}_i\text{) x (Projected Activity Level}_i\text{)}$$

Where i = each emission source participating in the averaging plan
N = the total number of emission units participating in the averaging plan.
Source Specific Allowable ER_i = Department imposed emission rate limit for emission $source_i$.

Projected activity $level_i$ = Estimate of future activity level for emission $source_i$

3) The aggregate of actual emissions from the sources participating in the plan must not exceed the aggregate of allowable emissions of those sources. The compliance will be verified by the following equation:

$$\Sigma_{i=1-N} \text{ (Source Specific Allowable ER}_i\text{) x (Actual Activity Level}_i\text{)} \geq \Sigma_{i=1-N} \text{ (Actual Emission Rate}_i\text{) x (Actual Activity Level}_i\text{)}$$

IV. ESTABLISHMENT OF EMISSION LIMITATIONS FOR COAL-FIRED COMBUSTION UNITS WITH RATED HEAT INPUT GREATER THAN 100 MMBTU/HR:

Following the installation of approved RACT technology, Section 129.91 (j) requires the Department to determine the RACT emission limitation for combustion units with rated heat inputs greater than 100 MMBtu/hr. The determination of this maximum limit is to be based upon emissions data obtained either from approved continuous emission monitoring system or an alternate approved methodology. The following

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procedure shall be used for establishing the final RACT emission limit. The Department may approve an alternate methodology if it was demonstrated that the alternate methodology is more appropriate than the one included in the guidance document. In cases involving multiple sources emitting through a single stack, the methodology to establish the individual emission limits will be approved on a case-by-case basis.

1. A minimum of 90% valid daily averages for a period not less than six months and no more than a year is required. Conventionally, arithmetic average of hourly emission rate (lb/mmBTU) is used calculate the daily average. As an alternate, the facility may use the mass-weighted method, i.e. dividing the total mass of NOx emitted for the day by the total heat input over the same period. The CEM must be certified for the approved method.

A longer period (longer than a year) may be approved if it is demonstrated that a longer period is necessary to represent the normal operation.

2. The data from step one is to be subjected to the Shapiro-Wilk Test of Normality. In this test, data is to be subjected to analysis in two formats. First, the raw data is tested for normal distribution. Second, the existing data is converted to natural logs and tested for log-normal distribution. Based upon these two analysis, the distribution with the highest resulting Shapiro-Wilk statistic will become the distribution for determining the emission limit.

Note: Shapiro-Wilk routines are available through the SAS statistical programs.

3. If the Shapiro-Wilk's test indicates normal distribution, the arithmetic mean of daily average of the data will be used in the final emission limit calculation. The arithmetic mean of the data is defined as follows:

$$\text{Arithmetic mean} = \sum_{i=1}^{n} X_i/n$$

Where n = number of data points and X_i = i^{th} data point

If the Shapiro-Wilk's test indicates log-normal is the best distribution, then the geometric mean of the data will be used in the final emission calculation. The geometric mean is defined as:

$$\text{Geometric mean} = \exp\left[\sum^{n} \frac{(\ln Xi)}{n} \right]$$

Where exp = the natural antilog of the expression

4. The final emission limit is then determined from the following equation (based on one exceedence per year):

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For normally distributed data:

$$\text{Emission rate} = \text{Arithmetic mean} + (2.777 * \text{Standard Deviation})$$

*
For log normally distributed data:

$$\text{Emission rate} = \text{Median} * (\text{Geometric dispersion})^{2.777}$$

Where Geometric dispersion = antilogarithm of standard deviation of the logarithm of data.

Median = 50th percentile of the distribution of x_i

The calculated emission limit must not generally exceed the preliminary limit imposed in the RACT approval.

Reference: Municipal Waste Combustion: Background Information for Promulgated Standards and Guidelines-Summary of Public Comments and Responses Appendices A to C, U.S. EPA, EPA-450/3-91-004, December 1990.

Appendix 2

NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT (NESCAUM)

MEMBERS:

CONNECTICUT BUREAU OF AIR MANAGEMENT
MAINE BUREAU OF AIR QUALITY CONTROL
MASSACHUSETTS DIVISION OF AIR QUALITY CONTROL
NEW HAMPSHIRE AIR RESOURCES DIVISION
NEW JERSEY OFFICE OF ENERGY
NEW YORK DIVISION OF AIR RESOURCES
RHODE ISLAND DIVISION OF AIR AND HAZARDOUS MATERIALS
VERMONT AIR POLLUTION CONTROL DIVISION

NESCAUM Stationary Source Committee Recommendation On NOx RACT for Industrial Boilers, Internal Combustion Engines and Combustion Turbines

September 18, 1992

The NESCAUM Stationary Source Review Committee is one of nine technical Committees established by the NESCAUM Board of Directors. The purpose of the committee is to provide an opportunity for engineers who review permits for new and existing sources to discuss common technical issues and provide some measure of consistency in the review of permits in the region. This recommendation has been developed in response to Sections 182(f) and 182(b)(2) of the Clean Air Act Amendments of 1990 (CAAA), which require states to impose Reasonably Available Control Technology (RACT) for sources that have the potential to emit nitrogen oxides (NOx) in excess of specified threshold amounts and are located in ozone nonattainment areas or in the ozone transport region. RACT is defined as follows:

> "the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility"

The CAAA requires states to develop and submit NOx RACT regulations to the US EPA by November 15, 1992. All regulated sources must be in compliance with the NOx RACT regulations by May 31, 1995.

In the Northeast, approximately 40 percent of the annual NOx emissions are from stationary sources and 60 percent are from mobile sources. NOx emissions react photochemically with volatile organic compounds (VOC) to form ground-level ozone. NOx emissions also react to form gaseous and particulate acids and other toxic air pollutants. Large portions of the NESCAUM region are currently in nonattainment for ozone, and up to 35 million people are exposed to unhealthy ozone levels each summer in the Northeast. The US EPA's Regional Oxidant Modeling for Northeast Transport (ROMNET) Report (June 1991), which is regarded as the most sophisticated analysis of the regional ozone problem, indicates that a NOx emission reduction of more than 55%, in conjunction with substantial VOC emission reductions, will be necessary to achieve the ozone health standard. In 1987, NOx emissions from all sources in the NESCAUM region totaled approximately 1.6 million tons. NOx emissions from the three source categories addressed in this recommendation constitute a large fraction of total NOx emissions in the NESCAUM region (ranging from 10 to 15% of total NOx emissions for individual states).

Based on this information and the requirement of 1990 CAAA, the committee has developed NOx RACT recommendations for: (1) Industrial Boilers, (2) Internal

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Combustion Engines, and (3) Combustion Turbines. The NOx RACT limits presented here attempt to account for variations in fuel type, design of combustion units and heat input rate.

For all units (industrial boilers, internal combustion engines, and combustion turbines) with high uncontrolled emission rates, which make a clear technical demonstration that NOx RACT emission limits are not feasible, states may set higher unit-specific alternative emission limitations. Such limitations would be based on the capabilities of all available and applicable technology for combustion modification.

NOx RACT for Industrial Boilers

Industrial boilers are steam-generating units that supply electric power and/or heat to an industrial, institutional or commercial operation, excluding boilers used by electric utilities to generate electricity.

The recommendation for NOx RACT for industrial boilers takes into account the maximum heat input rate of the boilers (in million of Btus/hour) and is as follows.

1. Small Boilers (Boilers < 50 MMBtu/hr)
NOx RACT for small boilers will require appropriate adjustment of combustion process to minimize NOx emissions. The requirements for combustion adjustment will be developed by the individual states.

2. Medium-Size Boilers (Heat Input Rate ≥ 50 MMBtu/hr but less than 100 MMBtu/hr)

   a. For boilers in this size range burning wood, coal or some fuel other than oil or gas, NOx RACT will be determined by the individual states on a case-by-case basis.

   b. For boilers in this size range burning natural gas, the recommended NOx RACT limit is a performance-based standard of 0.10 lb/MMBtu, to be met on a 1-hour averaging basis.

   c. For boilers in this size range burning #2 oil, the recommended NOx RACT limit is a performance-based standard of 0.12 lb/MMBtu, to be met on a 1-hour averaging basis.

   d. For boilers in this size range burning #4, #5, or #6 oil, the recommended NOx RACT is a technology-based standard requiring joint application of low-NOx burners and flue gas recirculation (with minimum circulation of 10 percent). In addition, sources will be required periodically to provide the states with data on nitrogen content of #4, #5 or #6 oil (percent weight basis).

   e. For b) and c) above, the performance-based standards are to be met on an annual, one-hour source test basis at steady state, maximum load conditions (average of three, one-hour stack tests).

3. Large Boilers (Boilers ≥ 100 MMBtu/hr)
The Committee recommends that all large industrial boilers, burning oil, gas coal or other fuels (for example wood), be treated the same as electric utility boilers and must

comply with NOx RACT for electric utilities boilers, as published by NESCAUM ("NESCAUM Stationary Source Committee Recommendation on NOx RACT for Utility Boilers," August 12, 1992).

NOx RACT for Internal Combustion Engines

The emission standards for internal combustion engines are for the control of NOx from existing internal combustion engines with a maximum heat input rate exceeding 3 MMBtu/hr. All proposed levels are based on a one-hour averaging period. Lean-Burn engines are those in which the amount of oxygen in the engine exhaust gases is 1.0% or more, by weight. Rich-burn engines are those in which the amount of oxygen in the engine exhaust gases is less than 1.0%, by weight. Rated brake horsepower (bhp) is as specified by the manufacturer and listed on the nameplate.

1. Rich-Burn Engines

    a. 1.5 grams per bhp-hr for gas-fired units

2. Lean-Burn Engines

    a. 2.5 grams per bhp-hr for gas-fired units

    b. 8 grams per bhp-hr for oil-fired units

The Stationary Source Review Committee believes that these NOx RACT limits are achievable through the application of three-way catalysts for rich-burn engines, and through the use of retarded engine timing or separate circuit after-cooling for lean-burn engines.

NOx RACT for Combustion Turbines

The emission standards outlined below are for the control of NOx from existing combustion turbines. The recommendation applies to combustion turbines rated at 25 MMBtu/hr or above (maximum heat input rate).

The proposed levels are based on a one-hour averaging period.

1. Simple Cycle Combustion Turbines

    a. 55 parts per million volume dry (ppvmd) (corrected to 15% oxygen) for gas-fired turbines without oil back-up.

    b. 75 ppmvd (corrected to 15% oxygen) for oil-fired turbines

    c. for gas-fired turbines with oil back-up:
        1. 55 ppmvd (15% oxygen) when operating on gas
        2. 75 ppmvd (15% oxygen) when operating on oil

2. Combined Cycle Combustion Turbines

    a. 42 ppmvd (corrected to 15 % oxygen) for gas-fired turbines without oil back-up

b. 65 ppmvd (corrected to 15% oxygen) for oil-fired turbines

c. For gas-fired turbines with oil back-up:
   1. 42 ppmvd (15% oxygen) when operating on gas
   2. 65 ppmvd (15% oxygen) when operating on oil

The Stationary Source Review Committee believes that these NOx RACT limits are achievable through the application of water or steam injection and dry low-NOx combustion technology. Higher emission limits may be specified for an individual unit, on a case-by-case basis, if the owner of the stationary combustion turbine can make a demonstration that water injection is not feasible or that low-NOx combustors are not available for the make and model of turbine. Water injection not being feasible refers to either the unavailability of water (i.e., restrictions placed on water use), excessive costs associated with purifying the water (i.e., cleaning up salt water) or other factors associated with either the turbine or the location of the turbine, at the discretion of the states and the US EPA.

These recommendations were adopted by the NESCAUM Board of Directors on September 17, 1992.

Appendix 3

LNB Cost analysis for combustion unit greater than 20 and less than 50 MMBtu/hr			
Boiler Size (MMBtu/hr)	20	50	Reference
DIRECT COSTS			
Equipment Cost	$128,700	$128,700	Washington State Dept of Ecology (2006) adjusted with CPI for 2020
Instrumenttation and Monitoring	$12,870	$12,870	(Typical 10% of EC)
Freight	$7,722	$7,722	6% of EC
Tax	$7,722	$7,722	6% of EC
Total Purchsed Equipment Cost (TEC)	$157,014	$157,014	
Direct Installation Cost			
Foundation and Support	$12,561	$12,561	8% of TEC
Handling and Erection	$21,982	$21,982	14% of TEC
Electric	$6,281	$6,281	4% of TEC
Piping	$3,140	$3,140	2% of TEC
Painting	$1,570	$1,570	1% of TEC
Indirect Installation Costs			
Engineering and Supervision	$15,701	$15,701	10% of TEC
Construction and Field Expenses	$7,851	$7,851	5% of TEC
Contractor fees	$15,701	$15,701	10% of TEC
Contingencies	$4,710	$4,710	3% of TEC
Other Indirect Costs			
Startup and Testing	$4,710	$4,710	3% of TEC
TOTAL CAPITAL COST (TCC)	$251,222	$251,222	
Direct Annual Costs			
Electricity	$26,280	$26,280	Vendor's assumption of $52.580 for 100 MMBtu/hr boiler
Material & Maintenance	$12,561	$12,561	5% of TCC (Most vendors)
Indirect Annual Costs			
Overhead	$7,537	$7,537	60% of Maintenance (EPA's OAQPS)
PropertyTax+Ins.+Admn.	$10,049	$10,049	(4% of TCC - OAQPS)
Capital Recovery (5.5% @ 20 yrs)	$21,027	$21,027	
TOTAL ANNUALIZED COST	$77,454	$77,454	
Uncontrolled NOx emissions (lb/MMBtu)	0.2	0.2	
Uncontrolled NOx emissions (tons/year)	17.52	43.80	
NOx removed TPY (50% Eff.)	8.76	21.90	
COST EFFECTIVENESS ($/Ton of NOx removed)	$8,841.78	$3,536.71	

Oxidation Catalyst cost analysis for combustion unit greater than 20 and less than 50 MMBtu/hr			
Boiler Size (MMBtu/hr)	20	50	Reference
DIRECT COSTS			
Equipment Cost	$232,788	$232,788	Grays Harbor Energy Project for 30 MMBtu/hr auxiliary boiler
Instrumenttation and Monitoring	$23,279	$23,279	(Typical 10% of EC)
Freight	$13,967	$13,967	6% of EC
Tax	$13,967	$13,967	6% of EC
Total Purchsed Equipment Cost (TEC)	$284,002	$284,002	

Appendix 3

Direct Installation Cost			
Foundation and Support	$22,720	$22,720	8% of TEC
Handling and Erection	$39,760	$39,760	14% of TEC
Electric	$11,360	$11,360	4% of TEC
Piping	$5,680	$5,680	2% of TEC
Painting	$2,840	$2,840	1% of TEC
Indirect Installation Cost			
Engineering and Supervision	$28,400	$28,400	10% of TEC
Construction and Field Expenses	$14,200	$14,200	5% of TEC
Contractor fees	$28,400	$28,400	10% of TEC
Contingencies	$8,520	$8,520	3% of TEC
Other Indirect Costs			
Startup and Testing	$8,520	$8,520	3% of TEC
TOTAL CAPITAL COST (TCC)	$454,403	$454,403	
Direct Annual Costs			
Electricity	$5,226	$5,226	$1,500 for 2500 hrs operation
Catalyst replacement	$5,000	$5,000	
Material & Maintenance	$22,720	$22,720	5% of TCC (Most vendors)
Indirect Annual Costs			
Overhead	$13,632	$13,632	60% of Maintenance (EPA's OAQPS)
PropertyTax+Ins.+Admn.	$18,176	$18,176	(4% of TCC - OAQPS)
Capital Recovery (5.5% @ 20 yrs)	$38,034	$38,034	
TOTAL ANNUALIZED COST	$102,788	$102,788	
Uncontrolled VOC emissions (lb/MMBtu)	0.0036	0.0036	VOC emission at 3 ppm corrected at 3% oxygen
Uncontrolled VOC emissions (tons/year)	0.32	0.79	
VOC removed TPY (50% Eff.)	0.16	0.39	
COST EFFECTIVENESS ($/Ton of VOC removed)	$651,876.31	$260,750.52	

Appendix 4

LNB Cost analysis for combustion unit with uncontrolled NOx emission at 5 tons per year		
Boiler Size (MMBtu/hr)	50	Reference
DIRECT COSTS		
Equipment Cost	$128,700	Washington State Dept of Ecology (2006) adjusted with CPI for 2020
Instrumenttation and Monitoring	$12,870	(Typical 10% of EC)
Freight	$7,722	6% of EC
Tax	$7,722	6% of EC
Total Purchsed Equipment Cost (TEC)	$157,014	
Direct Installation Cost		
Foundation and Support	$12,561	8% of TEC
Handling and Erection	$21,982	14% of TEC
Electric	$6,281	4% of TEC
Piping	$3,140	2% of TEC
Painting	$1,570	1% of TEC
Indirect Installation Cost		
Engineering and Supervision	$15,701	10% of TEC
Construction and Field Expenses	$7,851	5% of TEC
Contractor fees	$15,701	10% of TEC
Contingencies	$4,710	3% of TEC
Other Indirect Costs		
Startup and Testing	$4,710	3% of TEC
TOTAL CAPITAL INVESTMENT (TCI)	$251,222	
Direct Annual Costs		
Electricity	$26,280	Vendor's assumption of $52.580 for 100 MMBtu/hr boiler
Material & Maintenance	$12,561	5% of TCI (Most vendors)
Indirect Annual Costs		
Overhead	$7,537	60% of Maintenance (EPA's OAQPS)
PropertyTax+Ins.+Admn.	$10,049	(4% of TCI - OAQPS)
Capital Recovery (5.5% @ 20 yrs)	$21,027	
TOTAL ANNUALIZED COST	$77,454	
Uncontrolled NOx emissions (tons/year)	5.00	
NOx removed TPY (50% Eff.)	2.50	

Appendix 4

COST-EFFECTIVENESS ($/Ton NOx removed)	$30,981.60	
Oxidation Catalyst cost analysis for combustion unit with uncontrolled VOC emission at 2.7 tons per year		
Boiler Size (MMBtu/hr)	50	Reference
DIRECT COSTS		
Equipment Cost	$232,788	Grays Harbor Energy Project for 30 MMBtu/hr auxiliary boiler
Instrumenttation and Monitoring	$23,279	(Typical 10% of EC)
Freight	$13,967	6% of EC
Tax	$13,967	6% of EC
Total Purchsed Equipment Cost (TEC)	$284,002	
Direct Installation Cost		
Foundation and Support	$22,720	8% of TEC
Handling and Erection	$39,760	14% of TEC
Electric	$11,360	4% of TEC
Piping	$5,680	2% of TEC
Painting	$2,840	1% of TEC
Indirect Installation Cost		
Engineering and Supervision	$28,400	10% of TEC
Construction and Field Expenses	$14,200	5% of TEC
Contractor fees	$28,400	10% of TEC
Contingencies	$8,520	3% of TEC
Other Indirect Costs		
Startup and Testing	$8,520	3% of TEC
TOTAL CAPITAL INVESTMENT (TCI)	$454,403	
Direct Annual Costs		
Electricity	$5,226	$1,500 for 2500 hrs operation
Catalyst replacement	$5,000	
Material & Maintenance	$22,720	5% of TCI (Most vendors)
Indirect Annual Costs		
Overhead	$13,632	60% of Maintenance (EPA's OAQPS)
PropertyTax+Ins.+Admn.	$18,176	(4% of TCI - OAQPS)
Capital Recovery (5.5% @ 20 yrs)	$38,034	

Appendix 4

TOTAL ANNUALIZED COST	$102,788	
Uncontrolled VOC emissions (tons/year)	2.70	
VOC removed TPY (50% Eff.)	1.35	
COST-EFFECTIVENESS ($/Ton VOC removed)	$76,139.15	

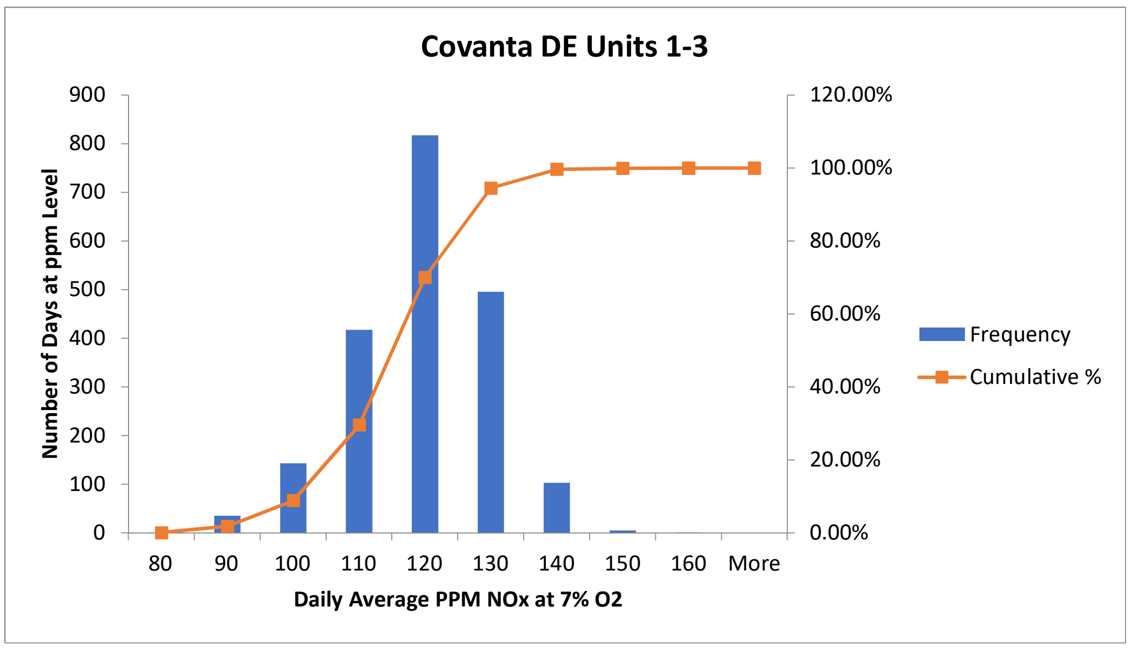
Appendix 5

Cost Analysis for SNCR for Municipal Waste Combustor		
Cost estimate	Assumed average large MWC in PA	Factors Used
Daily throughput municipal waste (tpd waste)	500	Asumed average large combustor (Range 300 - 600 tpd)
Hrs/Yr	8760	
Reference NOx emissions in lbs/hr	109.00	Permit limit for Covanta Plymouth 109 lb/hr and 180 ppm@7%O2
Total Capital Cost	$1,392,000	Based on $464,000 for 200 tpd MWC at Olmstead, MN for 2007
TOTAL CAPITAL COST (TCC)	$1,726,080.00	With CPI from 2007 - 2020 (1.24)
Direct Annual Costs		
Elecricity	$95,124	$0.0676 kw/hr
Chemical Cost (Urea/Ammonia)	$88,500	Based on $29,500 for 200 tpd MWC at Olmstead, MN for 2007
Administration (3% of maintenance+labor)	$3,154	3% of maintenance +labor
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material	$32,850	100% of maintenance labor
Indirect Annual Costs		
Annulized Capital Recovery Cost (20 yrs at 5.5%)	$144,473	TCC*0.0837
Property Taxes (1% of TCC-OAQPS)	$17,261	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS)	$17,261	1% of TCC (OAQPS)
Overhead (44% of Labor cost + 12% Material Cost)	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST	$470,892	This is close to Annual Operating cost*3 for Olmstead for 200 tpd MWC
Uncontrolled NOx TPY	477.42	
NOx removed TPY (40% Eff.)	190.97	
COST-EFFECTIVENESS ($/Ton NOx removed)	$2,465.82	

Appendix 6

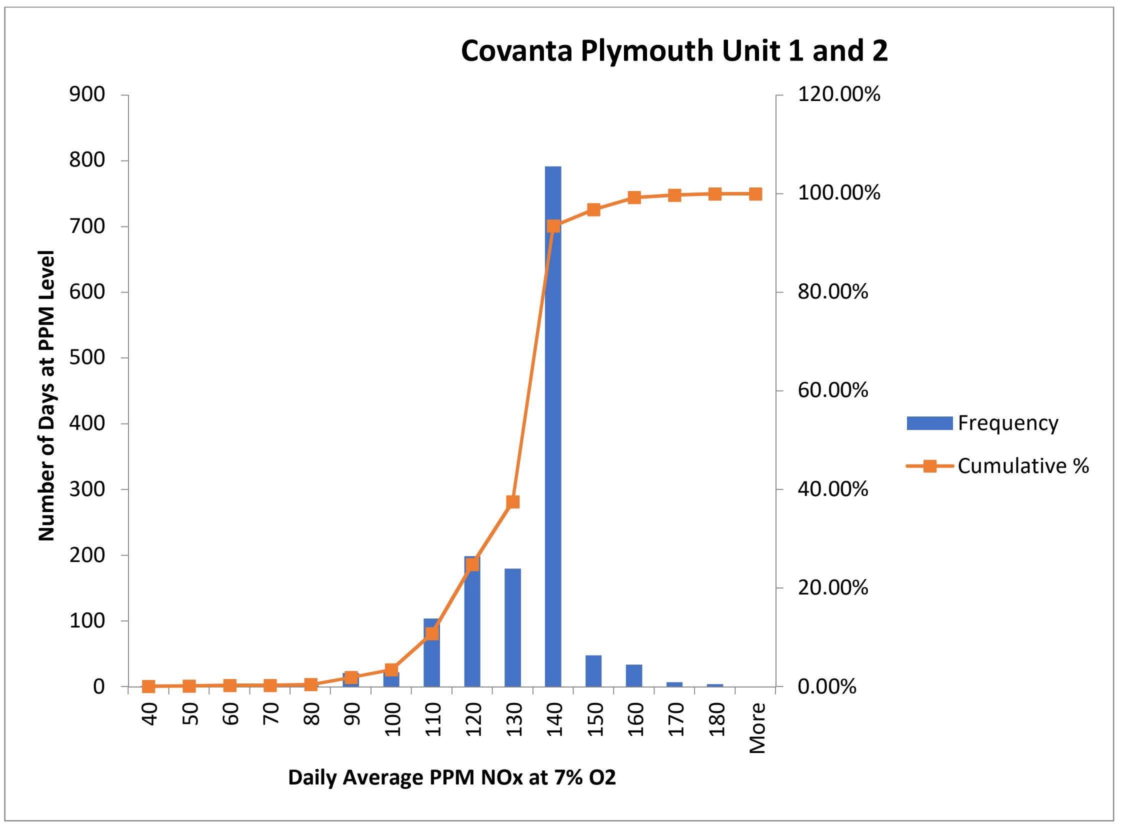
NOx emission test results from all MWCs for 2018 and 2019

Bin	*Frequency*	*Cumulative %*
80	1	0.05%
90	35	1.78%
100	143	8.86%
110	418	29.55%
120	818	70.05%
130	496	94.60%
140	103	99.70%
150	5	99.95%
160	1	100.00%
More	0	100.00%

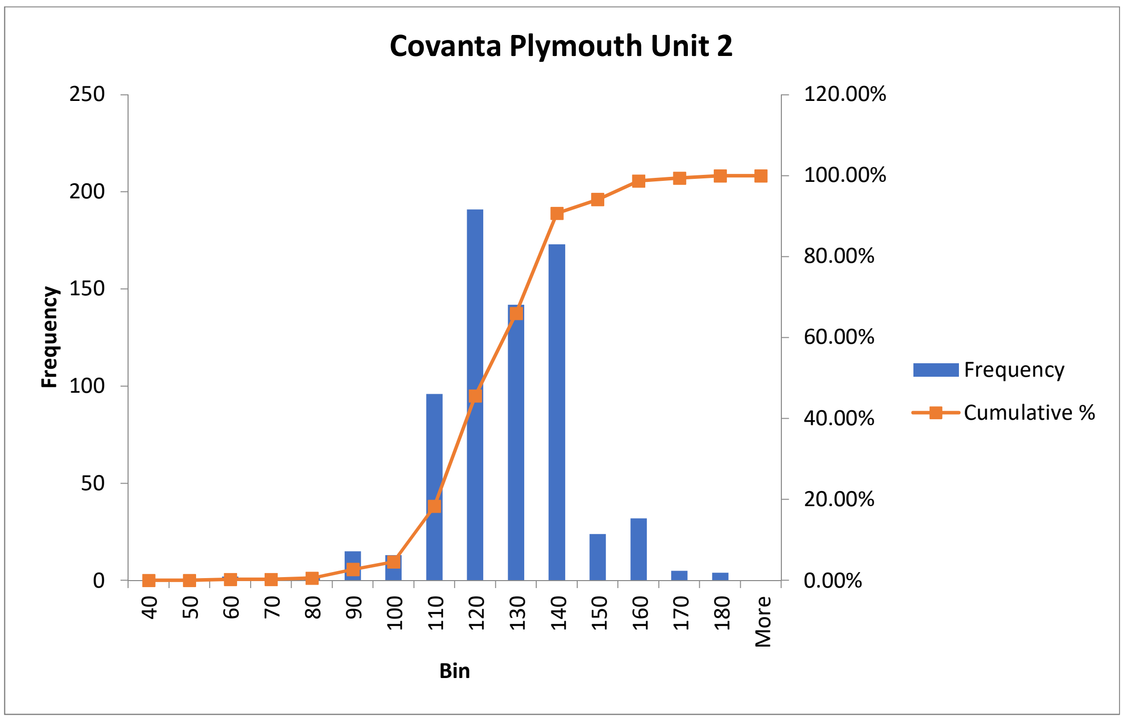


Bin	*Frequency*	*Cumulative %*
40	1	0.07%
50	1	0.14%
60	2	0.28%
70	0	0.28%
80	2	0.42%
90	21	1.91%
100	22	3.46%
110	104	10.80%
120	199	24.84%
130	180	37.54%
140	792	93.44%
150	48	96.82%
160	34	99.22%
170	7	99.72%
180	4	100.00%
More	0	100.00%

45 days over 150 PPM Nox
41 days occurred on unit 2
All but 5 of the 42 days occurred from 11/7/2019 to 1/8/2020

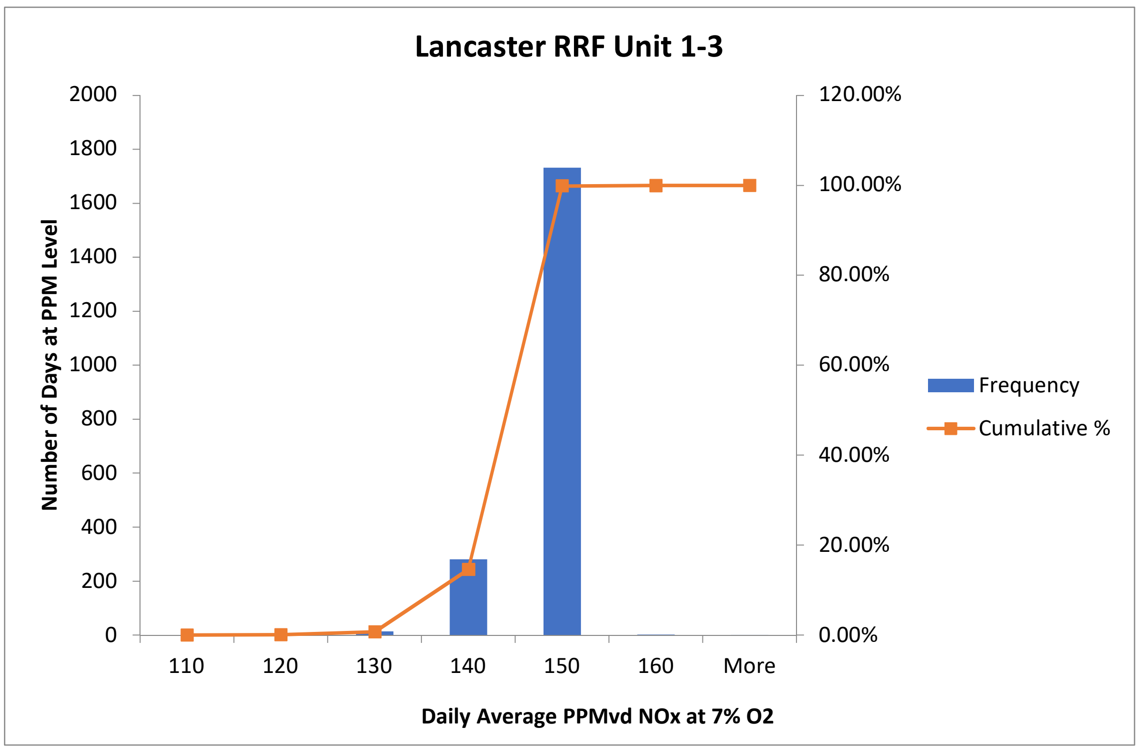


Bin	*Frequency*	*Cumulative %*
40	0	0.00%
50	0	0.00%
60	2	0.29%
70	0	0.29%
80	2	0.57%
90	15	2.72%
100	13	4.58%
110	96	18.31%
120	191	45.64%
130	142	65.95%
140	173	90.70%
150	24	94.13%
160	32	98.71%
170	5	99.43%
180	4	100.00%
More	0	100.00%

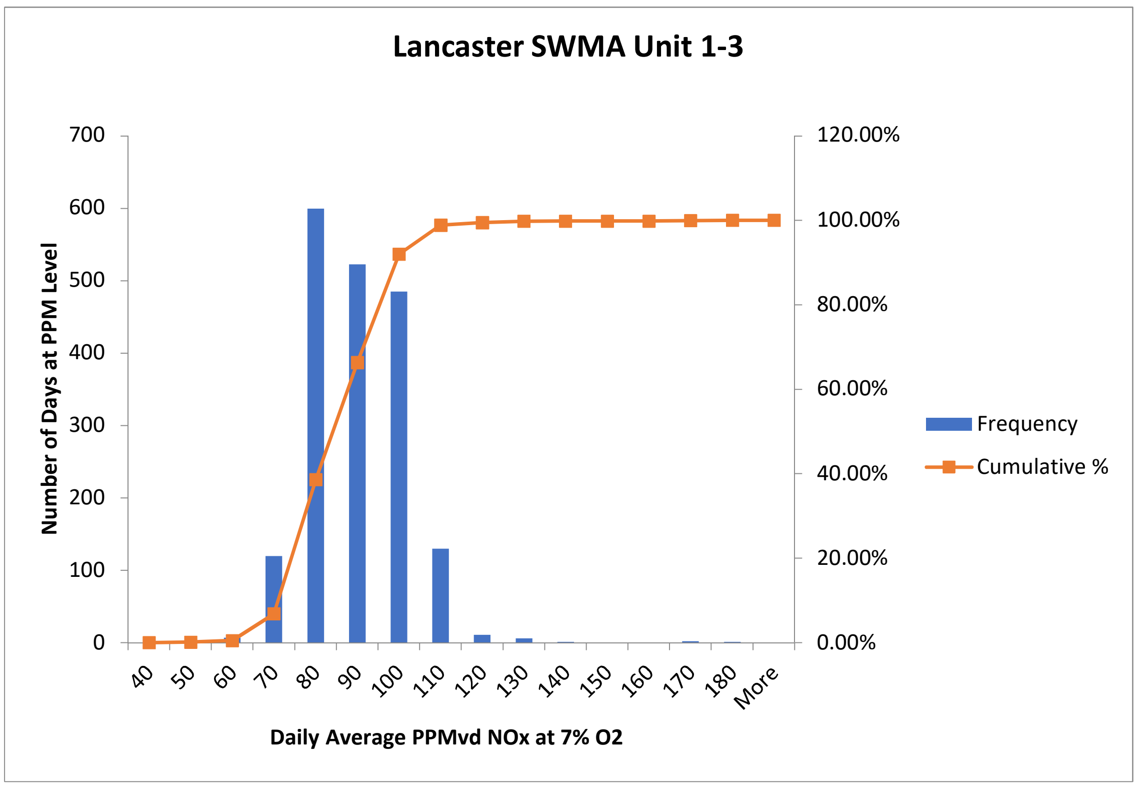


Appendix 6

Bin	*Frequency*	*Cumulative %*
110	0	0.00%
120	1	0.05%
130	14	0.74%
140	281	14.57%
150	1733	99.85%
160	2	99.95%
More	1	100.00%

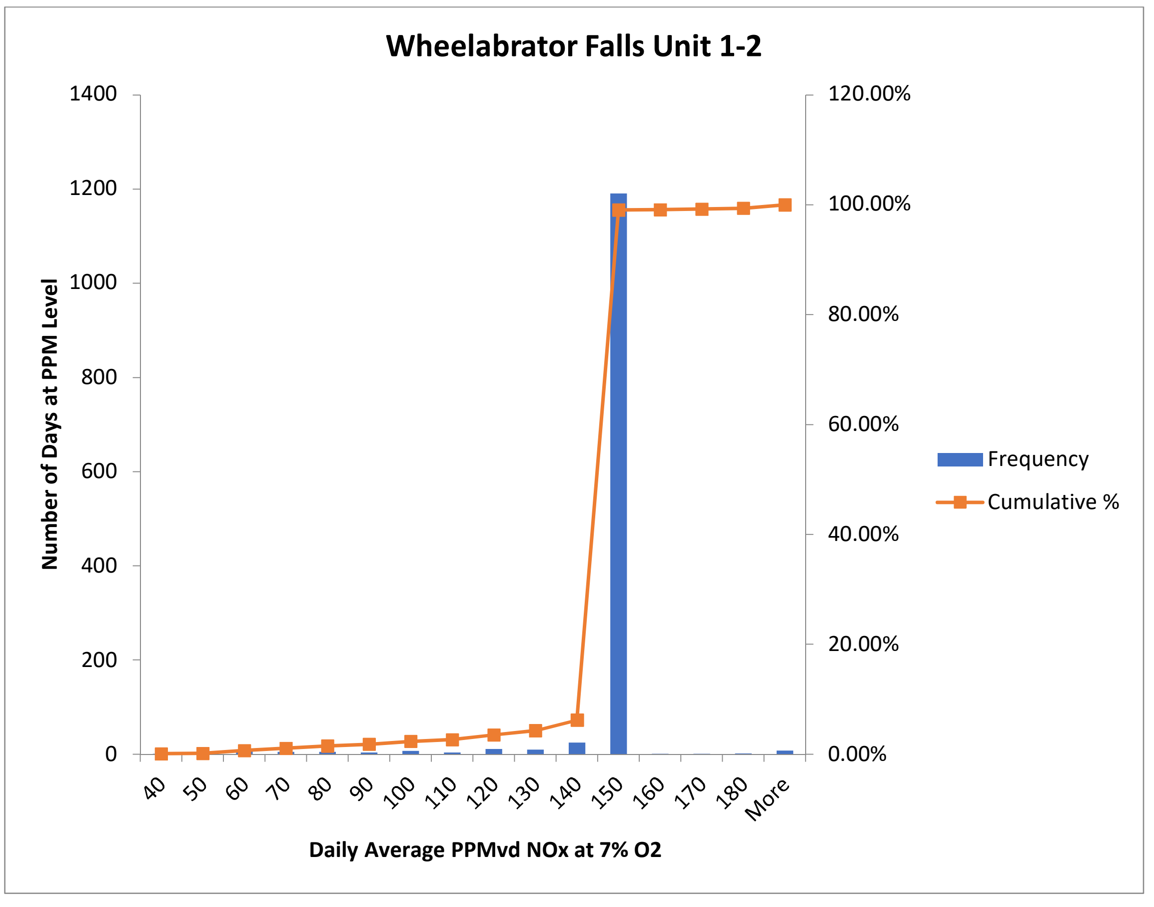


Bin	*Frequency*	*Cumulative %*
40	0	0.00%
50	2	0.11%
60	7	0.48%
70	120	6.83%
80	600	38.61%
90	523	66.31%
100	485	92.00%
110	130	98.89%
120	11	99.47%
130	6	99.79%
140	1	99.84%
150	0	99.84%
160	0	99.84%
170	2	99.95%
180	1	100.00%
More	0	100.00%



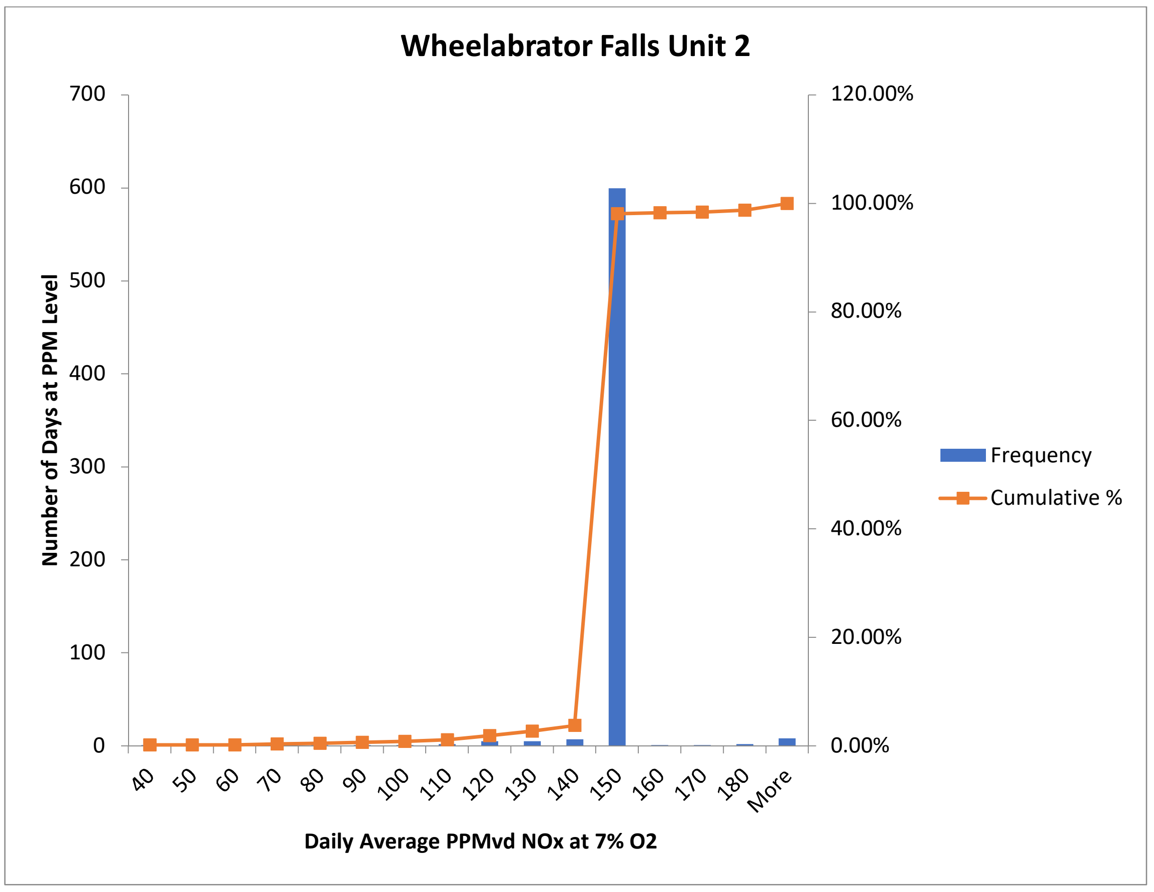
Bin	*Frequency*	*Cumulative %*
40	1	0.08%
50	1	0.16%
60	7	0.70%
70	5	1.09%
80	5	1.48%
90	4	1.79%
100	7	2.34%
110	4	2.65%
120	11	3.51%
130	10	4.29%
140	25	6.24%
150	1191	99.06%
160	1	99.14%
170	1	99.22%
180	2	99.38%
More	8	100.00%

12 days over 150 PPM Nox
Al occurred on unit 2



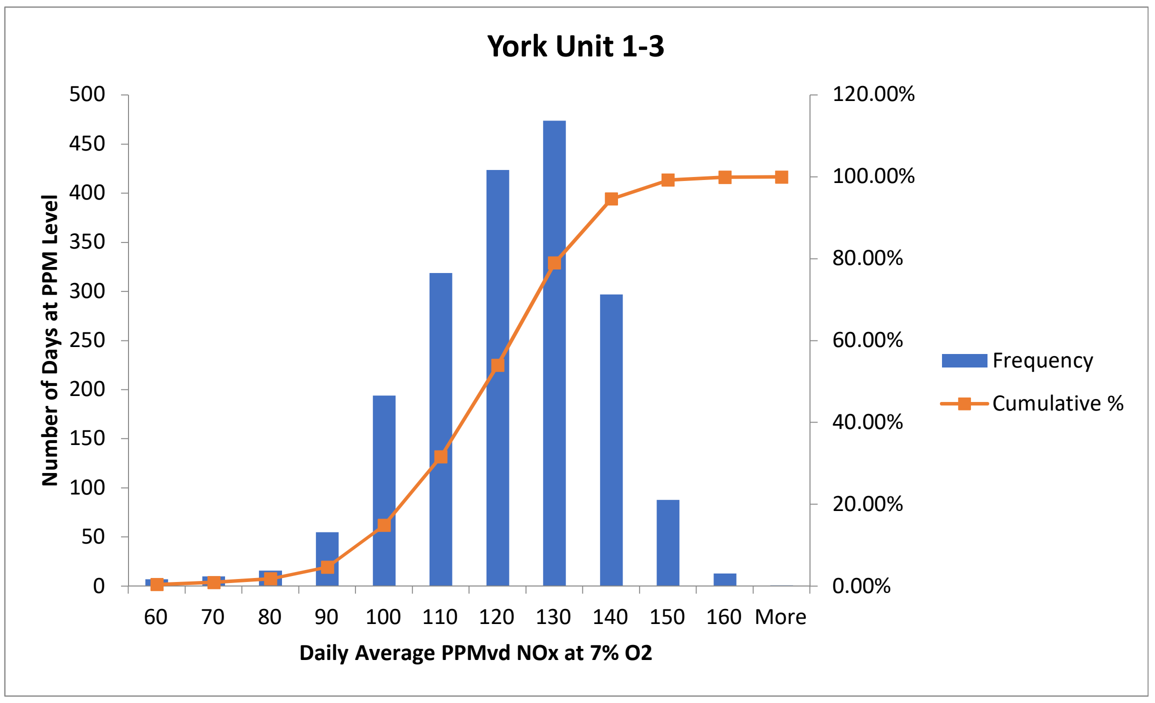
Appendix 6

Bin	Frequency	Cumulative %
40	1	0.16%
50	0	0.16%
60	0	0.16%
70	1	0.31%
80	1	0.47%
90	1	0.63%
100	1	0.79%
110	2	1.10%
120	5	1.89%
130	5	2.67%
140	7	3.77%
150	600	98.11%
160	1	98.27%
170	1	98.43%
180	2	98.74%
More	8	100.00%

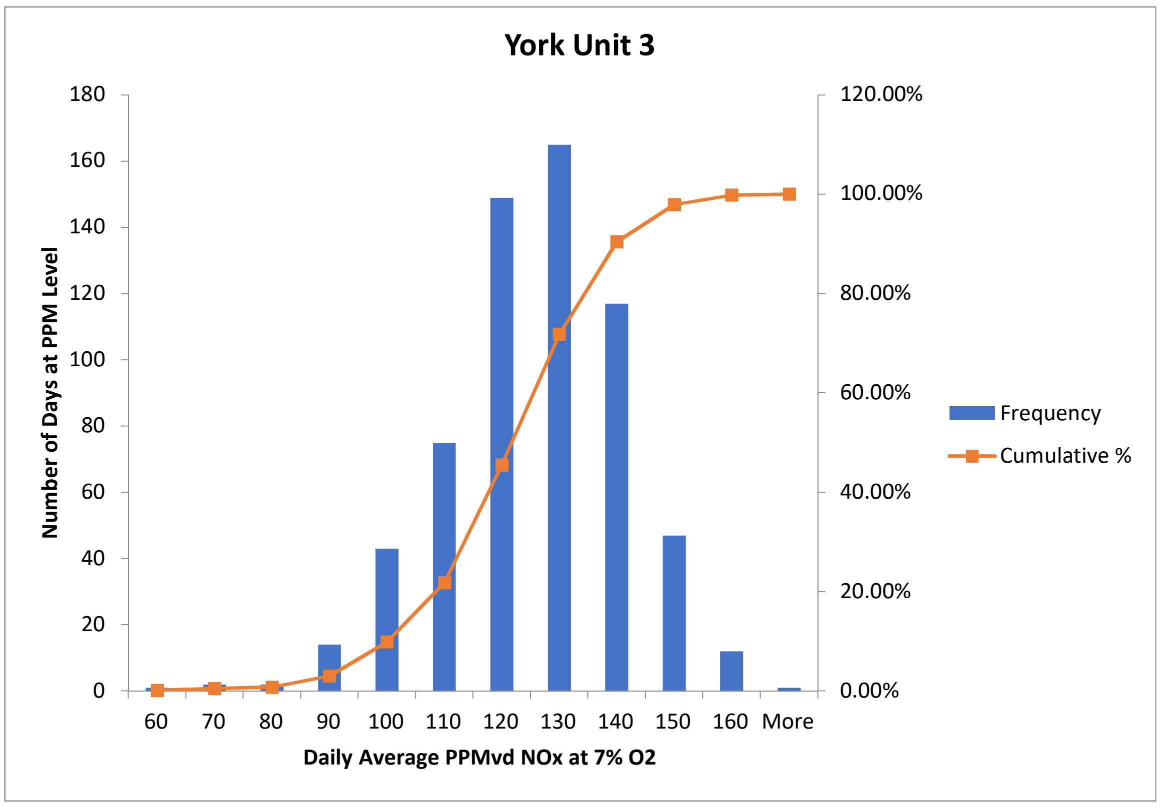


Bin	Frequency	Cumulative %
60	7	0.37%
70	10	0.90%
80	16	1.74%
90	55	4.64%
100	194	14.86%
110	319	31.66%
120	424	54.00%
130	474	78.98%
140	297	94.63%
150	88	99.26%
160	13	99.95%
More	1	100.00%

14 days over 150 PPM Nox
13 days occurred on unit 3
Al but 2 of the 13 days occurred from 4/18/2018 to 5/20/2018



Bin	Frequency	Cumulative %
60	1	0.16%
70	2	0.48%
80	2	0.80%
90	14	3.03%
100	43	9.87%
110	75	21.82%
120	149	45.54%
130	165	71.82%
140	117	90.45%
150	47	97.93%
160	12	99.84%
More	1	100.00%



Appendix 7

Cost Analysis for SCR for NG, propane, or liquid petroleum gas-fired combustion unit or process heater equal or > 50 MMBtu/hr			
Boiler Capacity MMBtu/hr	50	250	Factors/Reference used
Hrs/Yr	8760	8760	
NOx emissions (lb/MMBtu)	0.1	0.1	
TOTAL CAPITAL COST (TCC) in 2016	$1,884,950	$5,365,750	EPA cost spreadsheet for 50 MMBtu and 250 MMBtu/hr for 2016
TOTAL CAPITAL COST (TCC)	$2,054,596	$5,848,668	TCC in 2020 with CPI 1.09 from 2016 to 2020
Direct Annual Costs			
Elecricity	$16,595.25	$82,975.16	EPA cost spreadsheet for 50 MMBtu and 250 MMBtu/hr for 2016
Chemical Cost (Urea/Ammonia)	$9,156.00	$45,778.91	EPA cost spreadsheet for 50 MMBtu and 250 MMBtu/hr for 2016
Catalyst Replacement (costs/No. of years)	$4,738.23	$23,691.15	EPA cost spreadsheet for 50 MMBtu and 250 MMBtu/hr for 2016
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day	$32,850	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material	$32,850	$32,850	100% of maintenance labor
Indirect Annual Costs			
Administration (3% of maintenance+labor)	$3,154	$3,154	3% ofmaintenance +labor
Annulized Capital Recovery Cost (30 yrs at 5.5%)	$141,356	$402,388	TCC*0.0688
Property Taxes (1% of TCC-OAQPS)	$20,546	$58,487	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS)	$20,546	$58,487	1% of TCC (OAQPS)
Overhead (44% of Labor cost + 12% Material Cost)	$39,420.00	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST	$321,211	$780,080	
Uncontrolled NOx TPY	21.90	109.50	
NOx removed TPY (80% Eff.)	18	88	
COST-EFFECTIVENESS ($/Ton NOx removed)	$18,334	$8,905	

Appendix 8

SCR Cost Analysis for distillate oil-fired combustion unit or process heater equal or > 50 MMBtu/hr			
Boiler Capacity MMBtu/hr	50	250	Factors/reference used
Hrs/Yr	8760	8760	
NOx emissions (lb/MMBtu)	0.12	0.12	
TOTAL CAPITAL COST (TCC) in 2016	$1,557,377	$4,433,271	EPA cost spreadsheet for 50 and 250 MMBtu
TOTAL CAPITAL COST (TCC) in 2020	$1,697,541	$4,832,265	With CPI 1.09 from 2016 to 2020
Direct Annual Costs			
Elecricity	$18,829.75	$94,146.57	EPA cost spreadsheet for 50 and 250 MMBtu
Chemical Cost (Urea/Ammonia)	$10,987.20	$54,934.91	EPA cost spreadsheet for 50 and 250 MMBtu
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day	$32,850	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material	$32,850	$32,850	100% of maintenance labor
Catalyst Replacement (costs/No. of years)	$4,773.11	$23,863.37	EPA cost spreadsheet for 50 and 250 MMBtu
Indirect Annual Costs			
Administration (3% of maintenance+labor)	$3,154	$3,154	3% of maintenance+labor
Property Taxes (1% of TCC-OAQPS)	$16,975	$48,323	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS)	$15,574	$44,333	1% of TCC (OAQPS)
Annulized Capital Recovery Cost (30 yrs at 5.5%)	$116,791	$332,460	TCC*0.0688
Overhead (44% of Labor cost + 12% Material Cost)	$39,420.00	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST	$292,204	$706,334	
Uncontrolled NOx TPY	26.28	131.40	
NOx removed TPY (80% Eff.)	21	105	
COST-EFFECTIVENESS ($/Ton NOx removed)	$13,899	$6,719	

Appendix 9

SCR Cost Analysis for residual oil or other liquid-fired combustion unit or process heater equal or > 50 MMBtu/hr			
Boiler Capacity MMBtu/hr	50	250	Factors/reference used
Hrs/Yr	8760	8760	
NOx emissions (lb/MMBtu)	0.2	0.2	
TOTAL CAPITAL COST (TCC) in 2016	$1,557,377	$4,433,271	EPA cost spreadsheet for 50 and 250 MMBtu for 2016
TOTAL CAPITAL COST (TCC) in 2020	$1,697,541	$4,832,265	With CPI 1.09
Direct Annual Costs			
Elecricity	$18,829.75	$94,146.57	EPA cost spreadsheet for 50 and 250 MMBtu for 2016
Chemical Cost (Urea/Ammonia)	$18,312.00	$114,446.73	EPA cost spreadsheet for 50 and 250 MMBtu for 2016
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day	$32,850	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material	$32,850	$32,850	100% of maintenance labor
Catalyst Replacement (costs/No. of years)	$4,910.45	$24,980.62	EPA cost spreadsheet for 50 and 250 MMBtu for 2016
Indirect Annual Costs			
Administration (3% of maintenance+labor)	$3,154	$3,154	3% of maintenance+labor
Property Taxes (1% of TCC-OAQPS)	$16,975	$48,323	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS)	$15,574	$48,323	1% of TCC (OAQPS)
Annulized Capital Recovery Cost (30 yrs at 5.5%)	$116,791	$332,460	TCC*0.0688
Overhead (44% of Labor cost + 12% Material Cost)	$39,420.00	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST	$299,666	$770,953	
Uncontrolled NOx TPY	43.80	219.00	
NOx removed TPY (80% Eff.)	35	175	
COST-EFFECTIVENESS ($/Ton NOx removed)	$8,552	$4,400	

Appendix 10

SCR Cost Analysis for refinery gas-fired combustion unit or process heater equal to or > 50 MMBtu/hr			
Boiler Capacity MMBtu/hr	50	250	Factors/Reference used
Hrs/Yr	8760	8760	
NOx emissions (lb/MMBtu)	0.25	0.25	
TOTAL CAPITAL COST (TCC) in 2016	$1,884,950	$5,365,750	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
TOTAL CAPITAL COST (TCC) in 2020	$2,054,596	$5,848,668	With CPI 1.09 from 2016 to 2020
Direct Annual Costs			
Elecricity	$16,595.25	$82,975	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day	$32,850	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material	$32,850	$32,850	100% of maintenance labor
Chemical Cost (Urea/Ammonia)	$22,888.91	$114,447	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Catalyst Replacement (costs/No. of years)	$4,996.56	$24,981	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Indirect Annual Costs			
Administration (3% of maintenance+labor)	$3,154	$3,154	3% of maintenance + labor
Property Taxes (1% of TCC-OAQPS)	$20,546	$58,487	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS)	$20,546	$58,487	1% of TCC (OAQPS)
Annulized Capital Recovery Cost (30 yrs at 5.5%)	$129,685	$369,164	TCC*0.0688
Overhead (44% of Labor cost + 12% Material Cost)	$39,420.00	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST	$323,531	$816,813	
Uncontrolled NOx TPY	54.75	273.75	
NOx removed TPY (80% Eff.)	44	219	
COST-EFFECTIVENESS ($/Ton NOx removed)	$7,387	$3,730	

Appendix 11

SCR Cost Analysis for coal-fired combustion unit between 50 - 250 MMBtu/hr			
Boiler Capacity MMBtu/hr	50	250	Factors/Reference used
Hrs/Yr	8760	8760	
NOx emissions (lb/MMBtu)	0.45	0.45	
TOTAL CAPITAL COST (TCC) in 2016	$4,806,258	$13,280,762	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
TOTAL CAPITAL COST (TCC) in 2020	$5,238,821	$14,476,031	With CPI 1.09 from 2016 to 2020
Direct Annual Costs			
Annulized Capital Recovery Cost (30 yrs at 5.5%)	$360,431	$995,951	TCC*0.0688
Elecricity	$18,073.29	$90,366	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day	$32,850	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material	$32,850	$32,850	100% of maintenance labor
Chemical Cost (Urea/Ammonia)	$41,200.91	$206,005	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Catalyst Replacement (costs/No. of years)	$17,468.34	$19,763	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Indirect Annual Costs			
Administration (3% of maintenance+labor)	$3,154	$3,154	3% ofmaintenance +labor
Property Taxes (1% of TCC-OAQPS)	$52,388	$144,760	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS)	$52,388	$144,760	1% of TCC (OAQPS)
Overhead (44% of Labor cost + 12% Material Cost)	$39,420.00	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST	$650,223	$1,709,879	
Uncontrolled NOx TPY	98.55	492.75	
NOx removed TPY (80% Eff.)	79	394	
COST-EFFECTIVENESS ($/Ton NOx removed)	$8,247	$4,338	

Appendix 12

SNCR Cost Analysis for coal-fired combustion unit between 50 - 250 MMBtu/hr			
Boiler Capacity MMBtu/hr	50	250	Factors/Reference used
Hrs/Yr	8760	8760	
NOx emissions (lb/MMBtu)	0.45	0.45	
TOTAL CAPITAL COST (TCC) in 2016	$1,766,776	$4,045,623	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
TOTAL CAPITAL COST (TCC) in 2020	$1,925,786	$4,409,729	With CPI 1.09 from 2016 to 2020
Direct Annual Costs			
Elecricity	$832.76	$4,164	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Additional Water Cost	$683.43	$3,419	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Additional Ash Cost	$263.78	$1,318	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Additional Fuel Cost	$3,325.59	$16,628	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Chemical Cost (Urea/Ammonia)	$59,838.82	$299,196	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day	$32,850	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material	$32,850	$32,850	100% of maintenance labor
Indirect Annual Costs			
Administration (3% of maintenance+labor)	$3,154	$3,154	3% of maintenance +labor
Property Taxes (1% of TCC-OAQPS)	$19,258	$44,097	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS)	$19,258	$44,097	1% of TCC (OAQPS)
Annulized Capital Recovery Cost (30 yrs at 5.5%)	$121,554	$278,339	TCC*0.0688
Overhead (44% of Labor cost + 12% Material Cost)	$39,420.00	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST	$333,288	$799,532	
Uncontrolled NOx TPY	98.55	492.75	
NOx removed TPY (30% Eff.)	30	148	
COST-EFFECTIVENESS ($/Ton NOx removed)	$11,273	$5,409	

Appendix 13

Control technology	Control efficiency	Uncontrolled emission level lb/Mmbtu	Size of boiler Mmbtu/hr	Cost per ton of NOx 2016	Cost per ton of NOx 2020
SNCR	30%	0.16	250	$5,747	$6,207
SNCR	30%	0.16	500	$4,395	$4,747

SAMPLE CALCULATION

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat: 250 MMBtu/hour

What is the higher heating: 6,000 Btu/lb

What is the estimated actual annual fuel consumption?: 365,000,000 lbs/year

Is the boiler a fluid-bed boiler: Yes

Enter the net plant heat in: 10 MMBtu/MW

If the NPHR is not known, u

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite

Enter the sulfur content (%S) = 1.84 percent by weight

or Select the appropriate SO_2 emission rate: Not Applicable

*The sulfur content of 1.84% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 9.23 percent by weight

*The ash content of 9.23% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Appendix 13

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR (	365	days
Inlet NO_x Emissions (NOx_{in})	0.16	lb/MMBtu
Oulet NO_x Emissions (NOx_{o}	0.112	lb/MMBtu
Estimated Normalized Stoi	1.22	
Concentration of reagent a	29	Percent
Density of reagent as store	56	lb/ft^3
Concentration of reagent i	10	percent
Number of days reagent is	14	days
Estimated equipment life	30	Years
Select the reagent used	Ammonia	

Plant Elevation	250	Feet above sea level

Densities of typical SNCR reagents:

50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016			
CEPCI for 2016	541.7	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*		* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Fuel ($Cost_{fuel}$)	2.40	$/MMBtu*		
Reagent ($Cost_{reag}$)	0.29	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired	48.80	$/ton*		

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (I	0.015
Administrative Charges Fac	0.03

Appendix 13

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.40	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate (%)	5.5	Default bank prime rate	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	250	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	365,000,000	lbs/year
Actual Annual fuel consumption (Mactual) =		365,000,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	1.00	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8760	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	30	percent

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NOx removed per hour =	NOx_{in} x EF x Q_B =	12.00	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	52.56	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07		
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	> 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 250 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	62	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	8.3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	2,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0688

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	2.3	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	14	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.15	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1x10^6)/HHV =	2.3	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$682,343 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	$895,698 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	$935,477 in 2016 dollars

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Total Capital Investment (TCI) =	$3,267,573 in 2016 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$682,343 in 2016 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$895,698 in 2016 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$935,477 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$75,802 in 2016 dollars
Indirect Annual Costs (IDAC) =	$226,279 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$302,081 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$49,014 in 2016 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$21,355 in 2016 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$1,358 in 2016 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$518 in 2016 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$3,076 in 2016 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$481 in 2016 dollars

Appendix 13

Direct Annual Cost =		$75,802 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,470 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$224,809 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$226,279 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$302,081 per year in 2016 dollars
NOx Removed =	53 tons/year
Cost Effectiveness =	$5,747 per ton of NOx removed in 2016 dollars

Cost Effectivenss =	**$6,207**	**per ton of NOx removed in 2020 dollars**

Appendix 14

SCR Cost Analysis for CFB greater than 250 MMBtu/hr					
Control technology	Control efficiency	Uncontrolled emission level lb/Mmbtu	Size of boiler Mmbtu/hr	Cost per ton of NOx 2016	Cost per ton of NOx 2020
SCR	80%	0.16	250	$8,389	$9,060
SCR	80%	0.16	10000	$5,099	$5,507

SAMPLE CALCULATION

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1 3

Complete all of the highlighted data fields: 3

3

What is the maximum heat input rate (Q| 10,000 MMBtu/hour

What is the higher heating value (HHV) o| 11,841 Btu/lb

*HHV value of 11841 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 7,398,023,816 lbs/year

Enter the net plant heat input rate (NPHF| 10 MMBtu/MW

If the NPHR is not known, use the default

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1500 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous

Enter the sulfur content (%S) = 1.00 percent by weight 1

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided. 2

2

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

2

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- Method 1
- Method 2 (selected)
- Not applicable

2

Enter the following design parameters for the proposed SCR:

Appendix 14

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plan}	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.16	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.032	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst (H	24,000	hours
Estimated SCR equipment life	30	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value.

Concentration of reagent as stored (C_{store}	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

2
2
2

Select the reagent used: Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2016		
CEPCI for 2016	541.7	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	1.660	$/gallon for 50% urea*	* $1.66/gallon is a default value for 50% urea. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Appendix 14

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf.		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year.
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Check with fuel supplier or use U.S. Energy Information Administration
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$188,238,031	in 2016 dollars
Reagent Preparation Cost (RPC) =	$3,373,507	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$10,157,840	in 2016 dollars
Total Capital Investment (TCI) =	$262,300,191	in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) = $188,238,031 in 2016 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) = $3,373,507 in 2016 dollars

Appendix 14

Air Pre-Heater Costs (APHC)*	
For Coal-Fired Utility Boilers >25MW:	
$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:	
$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$	
Air Pre-Heater Costs (APH_{cost}) =	$0 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)	
For Coal-Fired Utility Boilers >25MW:	
$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$	
For Coal-Fired Industrial Boilers >250 MMBtu/hour:	
$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$	
Balance of Plant Costs (BOP_{cost}) =	$10,157,840 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$10,520,850 in 2016 dollars
Indirect Annual Costs (IDAC) =	$18,064,619 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$28,585,469 in 2016 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$1,311,501 in 2016 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$2,687,923 in 2016 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$3,316,186 in 2016 dollars
Annual Catalyst Replacement Cost =		$3,205,240 in 2016 dollars

For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.

Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 2 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		$10,520,850 in 2016 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$18,366 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$18,046,253 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$18,064,619 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$28,585,469 per year in 2016 dollars
NOx Removed =	5,606 tons/year
Cost Effectiveness =	$5,099 per ton of NOx removed in 2016 dollars
Cost Effectiveness =	**$5,507 per ton of NOx removed in 2020 dollars**

Appendix 15

SCR Cost Analysis for other solid fuel-fired combustion unit equal to or greater than 50 MMBtu/hr			
Boiler Capacity MMBtu/hr	50	250	Factors/Reference used
Hrs/Yr	8760	8760	
NOx emissions (lb/MMBtu)	0.25	0.25	
TOTAL CAPITAL COST (TCC) in 2016	$4,599,871	$12,972,142	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
TOTAL CAPITAL COST (TCC) in 2020	$5,013,859	$14,139,635	With CPI 1.09 from 2016 to 2020
Direct Annual Costs			
Elecricity	$18,073.29	$90,366	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Chemical Cost (Urea/Ammonia)	$22,888.91	$114,447	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Catalyst Replacement (costs/No. of years)	$17,468.34	$87,343	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day	$32,850	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material	$32,850	$32,850	100% of maintenance labor
Indirect Annual Costs			
Administration (3% of maintenance+labor)	$3,154	$3,154	3% ofmaintenance +labor
Property Taxes (1% of TCC-OAQPS)	$50,139	$141,396	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS)	$50,139	$141,396	1% of TCC (OAQPS)
Annulized Capital Recovery Cost (30 yrs at 5.5%)	$344,954	$972,807	TCC*0.0688
Overhead (44% of Labor cost + 12% Material Cost)	$39,420.00	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST	$611,935	$1,656,029	
Uncontrolled NOx TPY	54.75	273.75	
NOx removed TPY (80% Eff.)	44	219	
COST-EFFECTIVENSSS ($/Ton NOx removed)	$13,971	$7,562	

Appendix 16

SNCR Cost Analysis for other solid fuel-fired combustion unit equal to or greater than 50 MMBtu/hr			
Boiler Capacity MMBtu/hr	50	250	Factors/Reference used
Hrs/Yr	8760	8760	
NOx emissions (lb/MMBtu)	0.25	0.25	
TOTAL CAPITAL COST (TCC) in 2016	$1,706,180	$3,920,603	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
TOTAL CAPITAL COST (TCC) in 2020	$1,859,736	$4,273,457	With CPI 1.09 from 2016 to 2020
Direct Annual Costs			
Elecricity	$462.16	$2,313	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Additional Water Cost	$380.41	$1,900	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Additional Ash Cost	$146.06	$732	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Additional Fuel Cost	$1,847.55	$9,238	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day	$32,850	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material	$32,850	$32,850	100% of maintenance labor
Chemical Cost (Urea/Ammonia)	$33,243.91	$166,221	EPA spreadsheet for 50 and 250 mmbtu/hr boilers
Indirect Annual Costs			
Administration (3% of maintenance+labor)	$3,154	$3,154	3% of maintenance +labor
Property Taxes (1% of TCC-OAQPS)	$18,597	$42,735	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS)	$18,597	$42,735	1% of TCC (OAQPS)
Annulized Capital Recovery Cost (30 yrs at 5.5%)	$117,385	$269,737	TCC*0.0688
Overhead (44% of Labor cost + 12% Material Cost)	$39,420.00	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST	$298,934	$643,884	
Uncontrolled NOx TPY	54.75	273.75	
NOx removed TPY (30% Eff.)	16	82	
COST-EFFECTIVENESS ($/Ton NOx removed)	$18,200	$7,840	

Appendix 17

Cost Analysis for Oxidation Catalyst for combustion units and process heaters equal to or greater than 50 MMBtu/hr						
Boiler Size (MMBtu/hr)	50	100	150	200	250	Factors/References
TOTAL CAPITAL COST						
TOTAL CAPITAL COST (TCC)	$455,667	$911,333	$1,367,000	$1,822,667	$2,278,333	Company's proposed estimate
Catalyst Replacement	$43,333	$52,000	$78,000	$93,600	$112,320	Company Estimate for 30 MMBtu
Taxes, Insurance, Administration	$18,227	$36,453	$54,680	$72,907	$91,133	4% of TEC
Capital Recovery (5.5% @ 20 yrs)	$38,139	$76,279	$114,418	$152,557	$190,697	TCC*0.0837
TOTAL ANNUALIZED COST	$99,699	$164,732	$247,098	$319,064	$394,150	
Uncontrolled VOC emissions (lb/MMBtu)	0.0100	0.0100	0.0100	0.0100	0.0100	An average uncontrolled VOC emission rate
Uncontrolled VOC emissions (tons/year)	2.19	4.38	6.57	8.76	10.95	
VOC removed TPY (60% Eff.)	1.31	2.63	3.94	5.26	6.57	
COST-EFFECTIVENESS ($/Ton NOx removed)	$75,874.66	$62,683.38	$62,683.38	$60,704.69	$59,992.36	

Appendix 18

Cost Analysis for SCR for NG-fired combined cycle combustion turbines between 1000 and 4100 HP				
	HP		1000	4100
Operating Hours (h)	H		8760	8760
Fuel Consumption (MMBtu/h)	FC		10.99	21.99
TOTAL CAPITAL INVESTMENT (TCI)				
SCR Catalyst Housing and Control System	A	Based on vendors quote	$2,629,336.46	$3,234,608.16
Reductant Storage Tank	A'	Based on vendor's Quote	$70,585.47	$120,051.63
Total Purchased Equipment Costs	B	PA sales tax of 6% (1.06*(A+A'))	$2,861,917.25	$3,555,939.37
Direct Installation Costs	0.30B	OAQPS	$858,575.18	$1,066,781.81
Indirect Installation Costs	0.31B	OAQPS	$887,194.35	$1,102,341.20
Contingencies	0.24B	OAQPS 24% of equipment	$686,860.14	$853,425.45
Total Capital Costs	C	Sum(Row 8:Row 11)*1.11 (CPI)	$5,876,947.08	$7,302,121.50
Direct Annual Costs				
Power Costs		PC*H*PP	$1,122.45	$3,367.36
Reductant Costs		RC*H*RC	$20,006.53	$60,019.58
SCR Catalyst Replacement Costs		H/SCL*SCC	$8,978.71	$26,936.12
Replacement Parts		Vendor's quote	$4,976.13	$4,976.13
Operating Labor		OW*OH*SY	$11,804.10	$11,804.10
Maintenance Labor	D	MW*MH*SY	$6,493.35	$6,493.35
Total Direct Annual Costs	E	Sum(Row 15:Row 20)	$53,381.26	$113,596.63
Indirect Annual Costs				
Overhead	0.6D	OAQPS	$3,896.01	$3,896.01
Property Tax	0.02C	OAQPS using PA property tax of 2%	$52,586.73	$64,692.16
Insurance	0.01C	OAQPS	$26,293.36	$32,346.08
Administrative	0.02C	OAQPS	$52,586.73	$64,692.16
Capital Recovery		5.5% for 30 years=.0688	$404,333.96	$689,320.27
Total Indirect Annual Costs	F	Sum(Row 23:Row27)	$539,696.79	$854,946.69
TOTAL ANNUALIZED COST	G	E+F	$593,078.06	$968,543.32
Control Efficiency	CE		80%	80%
Potential to Emit (TPY)	PTE	NER*FC*H	26.61	53.22
Annual Estimated NOx Removal (TPY)	NR	PTE*CE	21.29	42.57
COST-EFFECTIVENESS ($/ton NOx removed)		G/NR	$27,861.63	$22,750.12
Assumptions:				
Power Consumption Rate (kW)	PC	Cost Manual Estimate (GP5A Turbine Ref sheet)	1.73	5.19
Industrial Retail Power Price ($/kWh)	PP	EIA Data		$0.0741
Reductant Consumption Rate (gal/h)	RC	Cost Manual Estimate (GP5A Turbine Ref sheet)	0.914	2.741
Reductant Price ($/gal)	RP	Vendor quote (Ref-Reductant consumption price)		$2.50
SCR Catalyst Cost ($)	SCC	Cost Manual Estimate (GP5A Turbine Ref sheet)	$20,499.33	$61,497.99
SCR Catalyst Life (h)	SCL	Vendor's quote		20,000
Operator Wages ($/h)	OW	MSC quote (Ref-Reductant consumption price)		$21.56
Operator Hours per Shift (h)	OH			0.50
Shifts per Year	SY	3 shifts/day*365 days/year		1,095
Maintenance Wages ($/h)	MW	MSC quote (Ref-Reductant consumption price)		$23.72

Appendix 18

Maintenance Hours per Shift	MH			0.25
Interest Rate	IR			5.50%
Equipment Life (y)	EL			30
NOx Emission Rate (ppm)	N		1.50E-04	1.5E-04
Molar Volume @ 14.7 psi and 70 F (scf/lb-mol)	MV			386.80
Molecular Weight of NO2 (lb/lb-mol)	MW			46.01
Fuel Volume (scf/MMBtu)	FD			8,743
Oxygen Content	OC			15%
NOx Emission Rate (lb/MMBtu)	NER		0.5526	0.5526

Appendix 19

Cost Analysis for oxidation catalyst for NG-fired combined cycle combustion turbines between 1000 - 4100 BHP			
	Cost	Costs	Costs
Uncontrolled NMNEC as propane (ppm @ 15% O2)	5	5	5
HP	1,000	1,500	4,100
MW	0.708215297	1.062322946	2.90368272
Hrs/Yr	8760	8760	8760
Heat Input (MMBtu/h)	11.06	16.59	45.346
NMNEHC Emission Rate (lb/MMBtu)	0.017659376	0.017659376	0.017659376
Total Uncontrolled NMNEHC emissions in Tons per Year	0.86	1.28	3.51
Total NMNEHC Removed in Tons per Year (60%)	0.51	0.77	2.10
TOTAL CAPITAL COST			
Oxidation Catalyst Purchased Equipment Costs	$96,566	$98,891	$110,981
Direct Installation Costs (0.30PEC)	$28,970	$29,667	$33,294
Total Indirect Installation Costs (0.27PEC)	$26,073	$26,701	$29,965
Project Contingency (0.15(DIC+IIC))	$8,256	$8,455	$9,489
Total Capital Investment	$159,865	$163,714	$183,729
Direct Annual Costs			
Operating and Supervisory Labor Costs	$18,889	$18,889	$18,889
Maintenance Cost	$2,897	$2,967	$3,329
Natural Gas Penalty	$2,664	$3,997	$10,924
Catalyst Disposal	$21	$32	$87
Annual Catalyst Replacement Cost	$2,317	$3,476	$9,500
Indirect Annual Costs			
Overhead (60% of Maintenance - EPA's OAQPS)	$1,738	$1,780	$1,998
PropertyTax+Ins.+Admn. (4% of TCI - EPA OAQPS)	$6,395	$6,549	$7,349
Capital Recovery (5.5% @ 20 yrs)	$13,381	$13,703	$15,378
Direct Annual Costs	$26,788	$29,359	$42,729
Indirect Annual Costs	$21,513	$22,031	$24,725
TOTAL ANNUALIZED COST	$48,302	$51,391	$67,454
COST-EFFECTIVENESS ($/Ton NMNEHC removed)	$94,104.00	$66,748.15	$32,052.93

Appendix 20

Cost Analysis for SCR for NG-fired combined cycle turbines between 4100 and 60000 HP								
Turbine Horsepower (bhp)	HP		4100	6000	11150	15900	30000	60000
Operating Hours (h)	H		8760	8760	8760	8760	8760	8760
Fuel Consumption (MMBtu/h)	FC		10.99	21.99	80.17	117.58	190.80	309.10
TOTAL CAPITAL INVESTMENT (TCI)								
SCR Catalyst Housing and Control System	A	Based on vendors quote	$905,690.28	$1,009,562.72	$1,291,111.68	$1,550,792.76	$2,321,635.56	$3,961,726.60
Reductant Storage Tank	A'	Based on vendor's Quote	$33,614.46	$42,103.48	$65,113.22	$86,335.80	$149,333.33	$283,370.64
Total Purchased Equipment Costs	B	PA sales tax of 6% (1.06*(A+A'))	$995,663.02	$1,114,766.17	$1,437,598.40	$1,735,356.27	$2,619,227.02	$4,499,803.08
Direct Installation Costs	0.30B	OAQPS	$298,698.91	$334,429.85	$431,279.52	$520,606.88	$785,768.11	$1,349,940.92
Indirect Installation Costs	0.31B	OAQPS	$308,655.54	$345,577.51	$445,655.50	$537,960.44	$811,960.38	$1,394,938.96
Contingencies	0.24B	OAQPS 24% of equipment	$238,959.13	$267,543.88	$345,023.62	$416,485.51	$628,614.49	$1,079,952.74
Total Capital Costs	C	Sum(Row 8:Row 11)*1.11 (CPI)	$2,044,594.02	$2,289,172.34	$2,952,108.31	$3,563,554.11	$5,378,582.69	$9,240,345.63
Direct Annual Costs								
Power Costs		PC*H*PP	$940.74	$2,822.23	$8,872.44	$9,005.94	$14,614.11	$29,228.22
Reductant Costs		RC*H*RC	$5,598.25	$16,794.76	$52,814.87	$77,461.83	$125,698.71	$251,397.42
SCR Catalyst Replacement Costs		H/SCL*SCC	$13,139.57	$39,418.71	$54,532.38	$68,471.44	$90,531.72	$181,063.43
Replacement Parts		Vendor's quote	$4,976.13	$4,976.13	$4,976.13	$4,976.13	$4,976.13	$4,976.13
Operating Labor		OW*OH*SY	$11,804.10	$11,804.10	$11,804.10	$11,804.10	$11,804.10	$11,804.10
Maintenance Labor	D	MW*MH*SY	$6,493.35	$6,493.35	$6,493.35	$6,493.35	$6,493.35	$6,493.35
Total Direct Annual Costs	E	Sum(Row 15:Row 20)	$42,952.15	$82,309.28	$139,493.28	$178,212.79	$254,118.12	$484,962.65
Indirect Annual Costs								
Overhead	0.6D	OAQPS	$3,896.01	$3,896.01	$3,896.01	$3,896.01	$3,896.01	$3,896.01
Property Tax	0.02C	OAQPS using PA property tax of 2%	$18,113.81	$20,191.25	$25,822.23	$31,015.86	$46,432.71	$79,234.53
Insurance	0.01C	OAQPS	$9,056.90	$10,095.63	$12,911.12	$15,507.93	$23,216.36	$39,617.27
Administrative	0.02C	OAQPS	$18,113.81	$20,191.25	$25,822.23	$31,015.86	$46,432.71	$79,234.53
Capital Recovery		5.5% for 30 years=.0688	$140,668.07	$216,097.87	$278,679.02	$336,399.51	$507,738.21	$872,288.63
Total Indirect Annual Costs	F	Sum(Row 23:Row27)	$189,848.59	$270,472.01	$347,130.62	$417,835.16	$627,715.99	$1,074,270.97
TOTAL ANNUALIZED COST	G	E+F	$232,800.74	$352,781.30	$486,623.90	$596,047.95	$881,834.11	$1,559,233.62
Control Efficiency	CE		80%	80%	80%	80%	80%	80%
Potential to Emit (TPY)	PTE	NER*FC*H	7.45	14.90	54.33	79.69	129.31	209.48
Annual Estimated NOx Removal (TPY)	NR	PTE*CE	5.96	11.92	43.46	63.75	103.45	167.58
COST-EFFECTIVENESS ($/ton NOx removed)		G/NR	$39,058.99	$29,594.58	$11,195.82	$9,350.01	$8,524.61	$9,304.30
Assumptions:								
Power Consumption Rate (kW)	PC	Cost Manual Estimate (GP5A Turbine Ref sheet)	1.45	4.35	13.67	13.87	22.51	45.03
Industrial Retail Power Price ($/kWh)	PP	EIA Data		$0.0741				
Reductant Consumption Rate (gal/h)	RC	Cost Manual Estimate (GP5A Turbine Ref sheet)	0.256	0.767	2.412	3.537	5.740	11.479
Reductant Price ($/gal)	RP	Vendor quote (Ref-Reductant consumption price)		$2.50				
SCR Catalyst Cost ($)	SCC	Cost Manual Estimate (GP5A Turbine Ref sheet)	$29,999.02	$89,997.06	$124,503.16	$156,327.48	$206,693.42	$413,386.84
SCR Catalyst Life (h)	SCL	Vendor's quote		20,000				
Operator Wages ($/h)	OW	MSC quote (Ref-Reductant consumption price)		$21.56				
Operator Hours per Shift (h)	OH			0.50				
Shifts per Year	SY	3 shifts/day*365 days/year		1,095				
Maintenance Wages ($/h)	MW	MSC quote (Ref-Reductant consumption price)		$23.72				

Appendix 20

Maintenance Hours per Shift	MH			0.25				
Interest Rate	IR			5.50%				
Equipment Life (y)	EL			30				
NOx Emission Rate (ppm)	N		4.20E-05	4.2E-05	4.2E-05	4.2E-05	4.2E-05	4.2E-05
Molar Volume @ 14.7 psi and 70 F (scf/lb-mol)	MV			386.80				
Molecular Weight of NO2 (lb/lb-mol)	MW			46.01				
Fuel Volume (scf/MMBtu)	FD	For 1050 Btu/scf Natural Gas @ 70 F		8,743				
Oxygen Content	OC			15%				
NOx Emission Rate (lb/MMBtu)	NER		0.1547	0.1547	0.1547	0.1547	0.1547	0.1547

Appendix 21

Cost Analysis for oxidation catalyst for NG-fired Combined cycle combustion turbines rated between 4,100 - 60,000 Bhp				
	Cost	Costs	Costs	Costs
Uncontrolled NMNEC as propane (ppm @ 15% O2)	5	5	5	5
HP	4,100	15,900	30,000	60,000
MW	2.90368272	11.26062323	21.24645892	42.49291785
Hrs/Yr	8760	8760	8760	8760
Fuel Consumption (MMBtu/h)	37.578	117.58	190.8	378.568
NMNEHC Emission Rate (lb/MMBtu)	0.017659376	0.017659376	0.017659376	0.017659376
Total Uncontrolled NMNEHC emissions in Tons per Year	2.91	9.09	14.76	29.28
Total NMNEHC Removed in Tons per Year (60%)	1.74	5.46	8.85	17.57
TOTAL CAPITAL COST				
Oxidation Catalyst Purchased Equipment Costs	$96,785	$205,918	$215,090	$215,090
Direct Installation Costs (0.30PEC)	$29,035	$61,775	$64,527	$64,527
Total Indirect Installation Costs (0.27PEC)	$26,132	$55,598	$58,074	$58,074
Project Contingency (0.15(DIC+IIC))	$8,275	$17,606	$18,390	$18,390
Total Capital Investment	$160,227	$340,897	$356,082	$356,082
Direct Annual Costs				
Operating and Supervisory Labor Costs	$18,889	$18,889	$18,889	$18,889
Maintenance Cost	$2,904	$6,178	$6,453	$6,453
Natural Gas Penalty	$12,553	$28,325	$45,964	$45,964
Catalyst Disposal	$130	$338	$637	$637
Annual Catalyst Replacement Cost	$14,204	$36,841	$69,512	$69,512
Indirect Annual Costs				
Overhead (60% of Maintenance (EPA OAQPS)	$1,742	$3,707	$3,872	$3,872
PropertyTax+Ins.+Admn. (4% of TCI - OAQPS)	$6,409	$13,636	$14,243	$14,243
Capital Recovery (5.5% @ 20 yrs)	$13,411	$28,533	$29,804	$29,804
TOTAL ANNUALIZED COST	$70,242	$136,446	$189,373	$189,373
COST-EFFECTIVENESS ($/Ton NMNEHC removed)	$40,277.24	$25,004.91	$21,386.45	$10,778.87

Appendix 22

Cost Analysis for oxidation catalyst for NG or Oil-fired simple cycle combustion turbines between 1000 - 4100 BHP			
	Cost	Costs	Costs
Uncontrolled NMNEC as propane (ppm @ 15% O2)	9	9	9
HP	1,000	1,500	4,100
MW	0.708215297	1.062322946	2.90368272
Hrs/Yr	8760	8760	8760
Heat Input (MMBtu/h)	11.06	16.59	45.346
NMNEHC Emission Rate (lb/MMBtu)	0.031786877	0.031786877	0.031786877
Total Uncontrolled NMNEHC emissions in Tons per Year	1.54	2.31	6.31
Total NMNEHC Removed in Tons per Year (60%)	0.92	1.39	3.79
TOTAL CAPITAL COST			
Oxidation Catalyst Purchased Equipment Costs	$96,566	$98,891	$110,981
Direct Installation Costs (0.30PEC)	$28,970	$29,667	$33,294
Total Indirect Installation Costs (0.27PEC)	$26,073	$26,701	$29,965
Project Contingency (0.15(DIC+IIC))	$8,256	$8,455	$9,489
Total Capital Investment	$159,865	$163,714	$183,729
Direct Annual Costs			
Operating and Supervisory Labor Costs	$18,889	$18,889	$18,889
Maintenance Cost	$2,897	$2,967	$3,329
Natural Gas Penalty	$2,664	$3,997	$10,924
Catalyst Disposal	$21	$32	$87
Annual Catalyst Replacement Cost	$2,317	$3,476	$9,500
Indirect Annual Costs			
Overhead (60% of Maintenance - EPA's OAQPS)	$1,738	$1,780	$1,998
PropertyTax+Ins.+Admn. (4% of TCI - EPA OAQPS)	$6,395	$6,549	$7,349
Capital Recovery (5.5% @ 20 yrs)	$13,381	$13,703	$15,378
Direct Annual Costs	$26,788	$29,359	$42,729
Indirect Annual Costs	$21,513	$22,031	$24,725
TOTAL ANNUALIZED COST	$48,302	$51,391	$67,454
COST-EFFECTIVENESS ($/Ton NMNEHC removed)	$52,280.00	$37,082.31	$17,807.19

Appendix 23

Cost Analysis for SCR for NG-fired simple cycle turbines between 4100 and 60000 HP							
Turbine Horsepower (bhp)	HP		4100	11150	15900	30000	60000
Operating Hours (h)	H		8760	8760	8760	8760	8760
Fuel Consumption (MMBtu/h)	FC		21.99	80.17	117.58	190.80	309.10
TOTAL CAPITAL INVESTMENT (TCI)							
SCR Catalyst Housing and Control System	A	Based on vendors quote	$905,690.28	$1,291,111.68	$1,550,792.76	$2,321,635.56	$3,961,726.60
Reductant Storage Tank	A'	Based on vendor's Quote	$33,614.46	$65,113.22	$86,335.80	$149,333.33	$283,370.64
Total Purchased Equipment Costs	B	PA sales tax of 6% (1.06*(A+A'))	$995,663.02	$1,437,598.40	$1,735,356.27	$2,619,227.02	$4,499,803.08
Direct Installation Costs	0.30B	OAQPS	$298,698.91	$431,279.52	$520,606.88	$785,768.11	$1,349,940.92
Indirect Installation Costs	0.31B	OAQPS	$308,655.54	$445,655.50	$537,960.44	$811,960.38	$1,394,938.96
Contingencies	0.24B	OAQPS 24% of equipment	$238,959.13	$345,023.62	$416,485.51	$628,614.49	$1,079,952.74
Total Capital Costs	C	Sum(Row 8:Row 11)*1.11 (CPI)	$2,044,594.02	$2,952,108.31	$3,563,554.11	$5,378,582.69	$9,240,345.63
Direct Annual Costs							
Power Costs		PC*H*PP	$2,822.23	$8,872.44	$9,005.94	$14,614.11	$29,228.22
Reductant Costs		RC*H*RC	$16,794.76	$52,814.87	$77,461.83	$125,698.71	$251,397.42
SCR Catalyst Replacement Costs		H/SCL*SCC	$26,936.12	$54,532.38	$68,471.44	$90,531.72	$181,063.43
Replacement Parts		Vendor's quote	$4,976.13	$4,976.13	$4,976.13	$4,976.13	$4,976.13
Operating Labor		OW*OH*SY	$11,804.10	$11,804.10	$11,804.10	$11,804.10	$11,804.10
Maintenance Labor	D	MW*MH*SY	$6,493.35	$6,493.35	$6,493.35	$6,493.35	$6,493.35
Total Direct Annual Costs	E	Sum(Row 15:Row 20)	$69,826.69	$139,493.28	$178,212.79	$254,118.12	$484,962.65
Indirect Annual Costs							
Overhead	0.6D	OAQPS	$3,896.01	$3,896.01	$3,896.01	$3,896.01	$3,896.01
Property Tax	0.02C	OAQPS using PA property tax of 2%	$18,113.81	$25,822.23	$31,015.86	$46,432.71	$79,234.53
Insurance	0.01C	OAQPS	$9,056.90	$12,911.12	$15,507.93	$23,216.36	$39,617.27
Administrative	0.02C	OAQPS	$18,113.81	$25,822.23	$31,015.86	$46,432.71	$79,234.53
Capital Recovery		5.5% for 30 years=.0688	$193,009.68	$278,679.02	$336,399.51	$507,738.21	$872,288.63
Total Indirect Annual Costs	F	Sum(Row 23:Row27)	$242,190.20	$347,130.62	$417,835.16	$627,715.99	$1,074,270.97
TOTAL ANNUALIZED COST	G	E+F	$312,016.89	$486,623.90	$596,047.95	$881,834.11	$1,559,233.62
Control Efficiency	CE		80%	80%	80%	80%	80%
Potential to Emit (TPY)	PTE	NER*FC*H	14.90	54.33	79.69	129.31	209.48
Annual Estimated NOx Removal (TPY)	NR	PTE*CE	11.92	43.46	63.75	103.45	167.58
COST-EFFECTIVENESS ($/ton NOx removed)		G/NR	$26,174.89	$11,195.82	$9,350.01	$8,524.61	$9,304.30
Assumptions:							
Power Consumption Rate (kW)	PC	Cost Manual Estimate (GP5A Turbine Ref sheet)	4.35	13.67	13.87	22.51	45.03
Industrial Retail Power Price ($/kWh)	PP	EIA Data	$0.0741				
Reductant Consumption Rate (gal/h)	RC	Cost Manual Estimate (GP5A Turbine Ref sheet)	0.767	2.412	3.537	5.740	11.479
Reductant Price ($/gal)	RP	Vendor quote (Ref-Reductant consumption price)	$2.50				
SCR Catalyst Cost ($)	SCC	Cost Manual Estimate (GP5A Turbine Ref sheet)	$61,497.99	$124,503.16	$156,327.48	$206,693.42	$413,386.84
SCR Catalyst Life (h)	SCL	Vendor's quote	20,000				
Operator Wages ($/h)	OW	MSC quote (Ref-Reductant consumption price)	$21.56				
Operator Hours per Shift (h)	OH		0.50				
Shifts per Year	SY	3 shifts/day*365 days/year	1,095				
Maintenance Wages ($/h)	MW	MSC quote (Ref-Reductant consumption price)	$23.72				

Appendix 23

Maintenance Hours per Shift	MH		0.25				
Interest Rate	IR		5.50%				
Equipment Life (y)	EL		30				
NOx Emission Rate (ppm)	N		4.2E-05	4.2E-05	4.2E-05	4.2E-05	4.2E-05
Molar Volume @ 14.7 psi and 70 F (scf/lb-mol)	MV		386.80				
Molecular Weight of NO2 (lb/lb-mol)	MW		46.01				
Fuel Volume (scf/MMBtu)	FD	For 1050 Btu/scf Natural Gas @ 70 F	8,743				
Oxygen Content	OC		15%				
NOx Emission Rate (lb/MMBtu)	NER		0.1547	0.1547	0.1547	0.1547	0.1547

Appendix 24

Cost Analysis for oxidation catalyst for NG or Oil-fired simple cycle turbines rated between 4,100 - 60,000 Bhp	Cost	Costs	Costs	Costs
Uncontrolled NMNEC as propane (ppm @ 15% O2)	9	9	9	9
HP	4,100	15,900	30,000	60,000
MW	2.90368272	11.26062323	21.24645892	42.49291785
Hrs/Yr	8760	8760	8760	8760
Fuel Consumption (MMBtu/h)	37.578	117.58	190.8	378.568
NMNEHC Emission Rate (lb/MMBtu)	0.031786877	0.031786877	0.031786877	0.031786877
Total Uncontrolled NMNEHC emissions in Tons per Year	5.23	16.37	26.56	52.71
Total NMNEHC Removed in Tons per Year (60%)	3.14	9.82	15.94	31.62
TOTAL CAPITAL COST				
Oxidation Catalyst Purchased Equipment Costs	$111,063	$166,169	$232,016	$372,116
Direct Installation Costs (0.30PEC)	$33,319	$49,851	$69,605	$111,635
Total Indirect Installation Costs (0.27PEC)	$29,987	$44,866	$62,644	$100,471
Project Contingency (0.15(DIC+IIC))	$9,496	$14,207	$19,837	$31,816
Total Capital Investment	$183,865	$275,093	$384,102	$616,038
Direct Annual Costs				
Operating and Supervisory Labor Costs	$18,889	$18,889	$18,889	$18,889
Maintenance Cost	$3,332	$4,985	$6,960	$11,163
Natural Gas Penalty	$12,553	$28,325	$45,964	$45,964
Catalyst Disposal	$130	$338	$637	$637
Annual Catalyst Replacement Cost	$9,500	$36,841	$69,512	$139,023
Indirect Annual Costs				
Overhead (60% of Maintenance (EPA OAQPS)	$1,999	$2,991	$4,176	$6,698
PropertyTax+Ins.+Admn. (4% of TCI - OAQPS)	$7,355	$11,004	$15,364	$24,642
Capital Recovery (5.5% @ 20 yrs)	$15,389	$23,025	$32,149	$51,562
TOTAL ANNUALIZED COST	$69,147	$126,398	$193,651	$298,578
COST-EFFECTIVENESS ($/Ton NMNEHC removed)	$22,027.64	$12,868.63	$12,149.80	$9,441.50

Appendix 25

Cost Analysis for SCR for oil-fired simple cycle turbines between 1000 and 4100 HP				
	HP		1000	4100
Operating Hours (h)	H		8760	8760
Fuel Consumption (MMBtu/h)	FC		10.99	21.99
TOTAL CAPITAL INVESTMENT (TCI)				
SCR Catalyst Housing and Control System	A	Based on vendors quote	$2,629,336.46	$3,234,608.16
Reductant Storage Tank	A'	Based on vendor's Quote	$70,585.47	$120,051.63
Total Purchased Equipment Costs	B	PA sales tax of 6% (1.06*(A+A'))	$2,861,917.25	$3,555,939.37
Direct Installation Costs	0.30B	OAQPS	$858,575.18	$1,066,781.81
Indirect Installation Costs	0.31B	OAQPS	$887,194.35	$1,102,341.20
Contingencies	0.24B	OAQPS 24% of equipment	$686,860.14	$853,425.45
Total Capital Costs	C	Sum(Row 8:Row 11)*1.11 (CPI)	$5,876,947.08	$7,302,121.50
Direct Annual Costs				
Power Costs		PC*H*PP	$1,122.45	$3,367.36
Reductant Costs		RC*H*RC	$20,006.53	$60,019.58
SCR Catalyst Replacement Costs		H/SCL*SCC	$8,978.71	$26,936.12
Replacement Parts		Vendor's quote	$4,976.13	$4,976.13
Operating Labor		OW*OH*SY	$11,804.10	$11,804.10
Maintenance Labor	D	MW*MH*SY	$6,493.35	$6,493.35
Total Direct Annual Costs	E	Sum(Row 15:Row 20)	$53,381.26	$113,596.63
Indirect Annual Costs				
Overhead	0.6D	OAQPS	$3,896.01	$3,896.01
Property Tax	0.02C	OAQPS using PA property tax of 2%	$52,586.73	$64,692.16
Insurance	0.01C	OAQPS	$26,293.36	$32,346.08
Administrative	0.02C	OAQPS	$52,586.73	$64,692.16
Capital Recovery		5.5% for 30 years=.0688	$404,333.96	$689,320.27
Total Indirect Annual Costs	F	Sum(Row 23:Row27)	$539,696.79	$854,946.69
TOTAL ANNUALIZED COST	G	E+F	$593,078.06	$968,543.32
Control Efficiency	CE		80%	80%
Potential to Emit (TPY)	PTE	NER*FC*H	27.97	55.94
Annual Estimated NOx Removal (TPY)	NR	PTE*CE	22.37	44.75
COST-EFFECTIVENESS ($/ton NOx removed)		G/NR	$26,506.45	$21,643.56
Assumptions:				
Power Consumption Rate (kW)	PC	Cost Manual Estimate (GP5A Turbine Ref sheet)	1.73	5.19
Industrial Retail Power Price ($/kWh)	PP	EIA Data		$0.0741
Reductant Consumption Rate (gal/h)	RC	Cost Manual Estimate (GP5A Turbine Ref sheet)	0.914	2.741
Reductant Price ($/gal)	RP	Vendor quote (Ref-Reductant consumption price)		$2.50
SCR Catalyst Cost ($)	SCC	Cost Manual Estimate (GP5A Turbine Ref sheet)	$20,499.33	$61,497.99
SCR Catalyst Life (h)	SCL	Vendor's quote		20,000
Operator Wages ($/h)	OW	MSC quote (Ref-Reductant consumption price)		$21.56
Operator Hours per Shift (h)	OH			0.50
Shifts per Year	SY	3 shifts/day*365 days/year		1,095
Maintenance Wages ($/h)	MW	MSC quote (Ref-Reductant consumption price)		$23.72

Appendix 25

Maintenance Hours per Shift	MH			0.25
Interest Rate	IR			5.50%
Equipment Life (y)	EL			30
NOx Emission Rate (ppm)	N		1.50E-04	1.5E-04
Molar Volume @ 14.7 psi and 70 F (scf/lb-mol)	MV			386.80
Molecular Weight of NO2 (lb/lb-mol)	MW			46.01
Fuel Volume (scf/MMBtu)	FD			9,190
Oxygen Content	OC			15%
NOx Emission Rate (lb/MMBtu)	NER		0.5809	0.5809

Appendix 26

Cost Analysis for SCR for Oil-fired simple cycle turbines between 4100 and 60000 HP							
Turbine Horsepower (bhp)	HP		4100	11150	15900	30000	60000
Operating Hours (h)	H		8760	8760	8760	8760	8760
Fuel Consumption (MMBtu/h)	FC		21.99	80.17	117.58	190.80	309.10
TOTAL CAPITAL INVESTMENT (TCI)							
SCR Catalyst Housing and Control System	A	Based on vendors quote	$2,070,149.22	$2,951,112.41	$3,544,669.17	$5,306,595.56	$9,055,375.09
Reductant Storage Tank	A'	Based on vendor's Quote	$76,833.04	$148,830.22	$197,338.97	$341,333.33	$647,704.33
Total Purchased Equipment Costs	B	PA sales tax of 6% (1.06*(A+A'))	$2,275,801.20	$3,285,939.19	$3,966,528.63	$5,986,804.62	$10,285,264.19
Direct Installation Costs	0.30B	OAQPS	$682,740.36	$985,781.76	$1,189,958.59	$1,796,041.39	$3,085,579.26
Indirect Installation Costs	0.31B	OAQPS	$705,498.37	$1,018,641.15	$1,229,623.87	$1,855,909.43	$3,188,431.90
Contingencies	0.24B	OAQPS 24% of equipment	$546,192.29	$788,625.41	$951,966.87	$1,436,833.11	$2,468,463.41
Total Capital Costs	C	Sum(Row 8:Row 11)*1.11 (CPI)	$4,673,357.76	$6,747,676.14	$8,145,266.53	$12,293,903.29	$21,120,790.01
Direct Annual Costs							
Power Costs		PC*H*PP	$3,097.33	$9,742.04	$10,281.36	$16,683.75	$33,367.49
Reductant Costs		RC*H*RC	$38,369.66	$120,719.70	$177,055.61	$287,311.34	$574,622.68
SCR Catalyst Replacement Costs		H/SCL*SCC	$26,936.12	$54,532.38	$68,471.44	$90,531.72	$181,063.43
Replacement Parts		Vendor's quote	$4,976.13	$4,976.13	$4,976.13	$4,976.13	$4,976.13
Operating Labor		OW*OH*SY	$11,804.10	$11,804.10	$11,804.10	$11,804.10	$11,804.10
Maintenance Labor	D	MW*MH*SY	$6,493.35	$6,493.35	$6,493.35	$6,493.35	$6,493.35
Total Direct Annual Costs	E	Sum(Row 15:Row 20)	$91,676.69	$208,267.71	$279,081.99	$417,800.38	$812,327.18
Indirect Annual Costs							
Overhead	0.6D	OAQPS	$3,896.01	$3,896.01	$3,896.01	$3,896.01	$3,896.01
Property Tax	0.02C	OAQPS using PA property tax of 2%	$41,402.98	$59,022.25	$70,893.38	$106,131.91	$181,107.50
Insurance	0.01C	OAQPS	$20,701.49	$29,511.12	$35,446.69	$53,065.96	$90,553.75
Administrative	0.02C	OAQPS	$41,402.98	$59,022.25	$70,893.38	$106,131.91	$181,107.50
Capital Recovery		5.5% for 30 years=.0688	$441,164.97	$636,980.63	$768,913.16	$1,160,544.47	$1,993,802.58
Total Indirect Annual Costs	F	Sum(Row 23:Row27)	$548,568.44	$788,432.26	$950,042.63	$1,429,770.26	$2,450,467.34
TOTAL ANNUALIZED COST	G	E+F	$640,245.13	$996,699.97	$1,229,124.62	$1,847,570.64	$3,262,794.52
Control Efficiency	CE		80%	80%	80%	80%	80%
Potential to Emit (TPY)	PTE	NER*FC*H	34.06	124.19	182.14	295.56	478.81
Annual Estimated NOx Removal (TPY)	NR	PTE*CE	27.25	99.35	145.71	236.45	383.04
COST-EFFECTIVENESS ($/ton NOx removed)		G/NR	$23,498.01	$10,032.40	$8,435.38	$7,813.88	$8,518.06
Assumptions:							
Power Consumption Rate (kW)	PC	Cost Manual Estimate (GP5A Turbine Ref sheet)	4.772	15.008	15.839	25.702	51.40
Industrial Retail Power Price ($/kWh)	PP	EIA Data	$0.0741				
Reductant Consumption Rate (gal/h)	RC	Cost Manual Estimate (GP5A Turbine Ref sheet)	1.752	5.512	8.085	13.119	26.238
Reductant Price ($/gal)	RP	Vendor quote (Ref-Reductant consumption price)	$2.50				
SCR Catalyst Cost ($)	SCC	Cost Manual Estimate (GP5A Turbine Ref sheet)	$61,497.99	$124,503.16	$156,327.48	$206,693.42	$413,386.84
SCR Catalyst Life (h)	SCL	Vendor's quote	20,000				
Operator Wages ($/h)	OW	MSC quote (Ref-Reductant consumption price)	$21.56				
Operator Hours per Shift (h)	OH		0.50				
Shifts per Year	SY	3 shifts/day*365 days/year	1,095				
Maintenance Wages ($/h)	MW	MSC quote (Ref-Reductant consumption price)	$23.72				

Appendix 26

Maintenance Hours per Shift	MH		0.25				
Interest Rate	IR		5.50%				
Equipment Life (y)	EL		30				
NOx Emission Rate (ppm)	N		9.6E-05	9.6E-05	9.6E-05	9.6E-05	9.6E-05
Molar Volume @ 14.7 psi and 70 F (scf/lb-mol)	MV		386.80				
Molecular Weight of NO2 (lb/lb-mol)	MW		46.01				
Fuel Volume (scf/MMBtu)	FD	For 1050 Btu/scf Natural Gas @ 70 F	8,743				
Oxygen Content	OC		15%				
NOx Emission Rate (lb/MMBtu)	NER		0.3537	0.3537	0.3537	0.3537	0.3537

Appendix 27

Cost Analysis for SCR for natural gas-fired lean-burn engines between 500 - 3,500 BHP

Engine Horsepower (bhp)	HP		500	1000	1380	1500	2000	2400	2500	3000
Operating Hours (h)	H		8760	8760	8760	8760	8760	8760	8760	8760
SCR Catalyst Housing and Control System	A	OAQPS	$232,597.34	$279,869.71	$315,796.70	$327,142.07	$374,414.44	$412,232.33	$421,686.80	$468,959.16
Reductant Storage Tank	A'	Vendor's quote	$6,014.80	$8,844.80	$10,995.60	$11,674.80	$14,504.80	$16,768.80	$17,334.80	$20,164.80
Total Purchased Equipment Costs	B	OAQPS with PA sales tax of 6%	$252,928.87	$306,037.38	$346,399.84	$359,145.88	$412,254.39	$454,741.19	$487,313.98	$542,927.60
Direct Installation Costs	0.30B	OAQPS	$75,878.66	$91,811.21	$103,919.95	$107,743.77	$123,676.32	$136,422.36	$146,194.19	$162,878.28
Indirect Installation Costs	0.31B	OAQPS	$78,407.95	$94,871.59	$107,383.95	$111,335.22	$127,798.86	$140,969.77	$151,067.33	$168,307.56
Contingencies	0.24B	OAQPS (0.15*(B+0.30B+0.31B))	$60,702.93	$73,448.97	$83,135.96	$86,195.01	$98,941.05	$109,137.89	$116,955.35	$130,302.62
TOTAL CAPITAL COST (TCC)	C	SUM ROW 7 - 10 with CPI	$519,389.44	$628,447.76	$711,332.08	$737,506.07	$846,564.39	$933,811.04	$1,000,699.25	$1,114,901.82
Direct Annual Costs										
Power Costs		PC*H*PP	$1,867.89	$2,481.09	$2,947.12	$3,094.28	$3,707.48	$4,198.04	$4,320.68	$4,933.88
Reductant Costs		RC*H*RC	$14,067.54	$28,135.07	$38,826.40	$42,202.61	$56,270.15	$67,524.17	$70,337.68	$84,405.22
SCR Catalyst Replacement Costs		H/SCL*SCC*1.11	$8,986.76	$9,751.08	$10,331.97	$10,515.41	$11,279.73	$11,891.19	$12,044.06	$12,808.38
Operating Labor plus 15% for Supervisor		OW*OH*SY*1.15	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72
Maintenance Labor plus Materials	D	MW*MH*SY*2	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70
Total Direct Annual Costs	E	Sum(Row 12:Row17)	$51,483.60	$66,928.66	$78,666.90	$82,373.72	$97,818.77	$110,174.82	$113,263.83	$128,708.89
Indirect Annual Costs										
Overhead	0.6D	OAQPS	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02
Property Tax	0.02C	OAQPS using PA property tax of 2%	$10,387.79	$12,568.96	$14,226.64	$14,750.12	$16,931.29	$18,676.22	$20,013.98	$22,298.04
Insurance	0.01C	OAQPS	$5,193.89	$6,284.48	$7,113.32	$7,375.06	$8,465.64	$9,338.11	$10,006.99	$11,149.02
Administrative	0.02C	OAQPS	$10,387.79	$12,568.96	$14,226.64	$14,750.12	$16,931.29	$18,676.22	$20,013.98	$22,298.04
Capital Recovery (5.5% @ 30 yrs)			$35,733.99	$43,237.21	$48,939.65	$50,740.42	$58,243.63	$64,246.20	$68,853.50	$76,711.25
Total Indirect Annual Costs	F	Sum(Row 20:Row24)	$69,495.49	$82,451.61	$92,298.27	$95,407.74	$108,363.87	$118,728.77	$126,680.48	$140,248.37
TOTAL ANNUALIZED COST	G	E+F	$120,979.09	$149,380.27	$170,965.17	$177,781.46	$206,182.64	$228,903.59	$239,944.32	$268,957.26
Control Efficiency	CE		80%	80%	80%	80%	80%	80%	80%	80%
Potential to Emit (TPY)	PTE	ER*HP*H/(454 g/lb*2000 lb/ton)	14.47	28.94	39.94	43.41	57.89	69.46	72.36	86.83
Annual Estimated NOx Removal (TPY)	NR	PTE*CE	11.58	23.15	31.95	34.73	46.31	55.57	57.89	69.46
COST EFFECTIVENESS ($/Ton of NOx removed)		G/NR	$10,449.87	$6,451.55	$5,350.56	$5,118.77	$4,452.38	$4,119.19	$4,145.16	$3,871.97
Assumptions:										
Power Consumption Rate (kW)	PC	OAQPS	2.88	3.82	4.54	4.77	5.71	6.47	6.66	7.60
Industrial Retail Power Price ($/kWh)	PP	EIA Data	$0.0741	$0.0741	$0.0741	$0.0741	$0.0741	$0.0741		
Reductant Consumption Rate (gal/h)	RC	OAQPS	0.642	1.285	1.773	1.927	2.569	3.083	3.212	3.854
Reductant Price ($/gal)	RP	Vendor's quote			$2.50					
SCR Catalyst Cost ($)	SCC	OAQPS	$18,484.43	$20,056.53	$21,251.33	$21,628.63	$23,200.73	$24,458.41	$24,772.83	$26,344.94
SCR Catalyst Life (h)	SCL	Vendor's quote			20,000					
Operator Wages ($/h)	OW	MSC quote ($21.56/hr)			$21.56					
Operator Hours per Shift (h)	OH				0.50					
Shifts per Year	SY	3 shifts/day*365 days/year			1,095					
Maintenance Wages ($/h)	MW	MSC quote			$23.72					
Maintenance Hours per Shift	MH				0.25					
Interest Rate	IR				5.50%					
Equipment Life (y)	EL				30					
NOx Emission Rate (g/bhp-h)	NER	Uncontrolled NOx Emissions >500 bhp			3.0					

Appendix 28

Cost Analysis for SCR for natural gas-fired lean-burn engines rated at Greater than 3500 BHP							
Engine Horsepower (bhp)	HP		3500	4000	4500	4735	5000
Operating Hours (h)	H		8760	8760	8760	8760	8760
SCR Catalyst Housing and Control System	A	OAQPS	$516,231.53	$563,503.89	$610,776.25	$632,994.26	$658,048.62
Reductant Storage Tank	A'	Vendor's quote	$22,994.80	$25,824.80	$28,654.80	$29,984.90	$31,484.80
Total Purchased Equipment Costs	B	OAQPS with PA sales tax of 6%	$598,541.22	$654,154.85	$709,768.47	$735,906.87	$765,382.09
Direct Installation Costs	0.30B	OAQPS	$179,562.37	$196,246.45	$212,930.54	$220,772.06	$229,614.63
Indirect Installation Costs	0.31B	OAQPS	$185,547.78	$202,788.00	$220,028.23	$228,131.13	$237,268.45
Contingencies	0.24B	OAQPS (0.15*(B+0.30B+0.31B))	$143,649.89	$156,997.16	$170,344.43	$176,617.65	$183,691.70
TOTAL CAPITAL COST (TCC)	C	SUM ROW 7 - 10 with CPI	$1,229,104.40	$1,343,306.98	$1,457,509.55	$1,511,184.76	$1,571,712.13
Direct Annual Costs							
Power Costs		PC*H*PP	$5,547.07	$6,160.27	$6,773.47	$7,061.67	$7,386.66
Reductant Costs		RC*H*RC	$98,472.75	$112,540.29	$126,607.83	$133,219.57	$140,675.36
SCR Catalyst Replacement Costs		H/SCL*SCC*1.11	$13,572.71	$14,337.03	$15,101.35	$15,460.59	$15,865.68
Operating Labor plus 15% for Supervisor		OW*OH*SY*1.15	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72
Maintenance Labor plus Materials	D	MW*MH*SY*2	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70
Total Direct Annual Costs	E	Sum(Row 12:Row17)	$144,153.95	$159,599.00	$175,044.06	$182,303.24	$190,489.12
Indirect Annual Costs							
Overhead	0.6D	OAQPS	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02
Property Tax	0.02C	OAQPS using PA property tax of 2%	$24,582.09	$26,866.14	$29,150.19	$30,223.70	$31,434.24
Insurance	0.01C	OAQPS	$12,291.04	$13,433.07	$14,575.10	$15,111.85	$15,717.12
Administrative	0.02C	OAQPS	$24,582.09	$26,866.14	$29,150.19	$30,223.70	$31,434.24
Capital Recovery (5.5% @ 30 yrs)			$84,569.01	$92,426.76	$100,284.51	$103,977.66	$108,142.27
Total Indirect Annual Costs	F	Sum(Row 20:Row24)	$153,816.25	$167,384.13	$180,952.01	$187,328.91	$194,519.89
TOTAL ANNUALIZED COST	G	E+F	$297,970.19	$326,983.13	$355,996.07	$369,632.15	$385,009.01
Control Efficiency	CE		80%	80%	80%	80%	80%
Potential to Emit (TPY)	PTE	ER*HP*H/(454 g/lb*2000 lb/ton)	101.30	115.77	130.24	137.04	144.71
Annual Estimated NOx Removal (TPY)	NR	PTE*CE	81.04	92.62	104.19	109.64	115.77
COST EFFECTIVENESS ($/Ton of NOx removed)		G/NR	$3,676.84	$3,530.50	$3,417	$3,371	$3,326
Assumptions:							
Power Consumption Rate (kW)	PC	OAQPS	8.55	9.49	10.43	10.88	11.38
Industrial Retail Power Price ($/kWh)	PP	EIA Data					
Reductant Consumption Rate (gal/h)	RC	OAQPS	4.496	5.139	5.781	6.083	6.424
Reductant Price ($/gal)	RP	Vendor's quote					
SCR Catalyst Cost ($)	SCC	OAQPS	$27,917.04	$29,489.14	$31,061.24	$31,800.13	$32,633.34
SCR Catalyst Life (h)	SCL	Vendor's quote					
Operator Wages ($/h)	OW	MSC quote ($21.56/hr)					
Operator Hours per Shift (h)	OH						
Shifts per Year	SY	3 shifts/day*365 days/year					
Maintenance Wages ($/h)	MW	MSC quote					
Maintenance Hours per Shift	MH						
Interest Rate	IR						
Equipment Life (y)	EL						
NOx Emission Rate (g/bhp-h)	NER	Uncontrolled NOx Emissions >500 bhp					

Appendix 29

Cost Analysis for SCR for oil-fired engines greater than 500 BHP

Engine Horsepower (bhp)	HP		500	1000	1380	1500	2000	2400	2500	3000	3500	4000	4500	4735	5000
Operating Hours (h)	H		8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760
SCR Catalyst Housing and Control System	A	OAQPS	$160,950.00	$321,900.00	$444,222.00	$482,850.00	$643,800.00	$772,560.00	$804,750.00	$965,700.00	$1,126,650.00	$1,287,600.00	$1,448,550.00	$1,524,196.50	$1,609,500.00
Reductant Storage Tank	A'	Vendor's quote	$6,014.80	$8,844.80	$10,995.60	$11,674.80	$14,504.80	$16,768.80	$17,334.80	$20,164.80	$22,994.80	$25,824.80	$28,654.80	$29,984.90	$31,484.80
Total Purchased Equipment Costs	B	OAQPS with PA sales tax of 6%	$176,982.69	$350,589.49	$482,530.66	$524,196.29	$697,803.09	$836,688.53	$912,514.13	$1,094,309.93	$1,276,105.73	$1,457,901.53	$1,639,697.33	$1,725,141.35	$1,821,493.13
Direct Installation Costs	0.30B	OAQPS	$53,094.81	$105,176.85	$144,759.20	$157,258.89	$209,340.93	$251,006.56	$273,754.24	$328,292.98	$382,831.72	$437,370.46	$491,909.20	$517,542.41	$546,447.94
Indirect Installation Costs	0.31B	OAQPS	$54,864.63	$108,682.74	$149,584.50	$162,500.85	$216,318.96	$259,373.44	$282,879.38	$339,236.08	$395,592.78	$451,949.47	$508,306.17	$534,793.82	$564,662.87
Contingencies	0.24B	OAQPS (0.15*(B+0.30B+0.31B))	$42,475.85	$84,141.48	$115,807.36	$125,807.11	$167,472.74	$200,805.25	$219,003.39	$262,634.38	$306,265.37	$349,896.37	$393,527.36	$414,033.92	$437,158.35
TOTAL CAPITAL COST (TCC)	C	SUM ROW 7 - 10 with CPI	$363,433.95	$719,935.51	$990,876.70	$1,076,437.08	$1,432,938.64	$1,718,139.89	$1,873,847.76	$2,247,165.44	$2,620,483.11	$2,993,800.79	$3,367,118.46	$3,542,577.77	$3,740,436.14
Direct Annual Costs															
Power Costs		PC*H*PP	$993.15	$1,986.29	$2,741.09	$2,979.44	$3,972.59	$4,767.11	$4,965.74	$5,958.88	$6,952.03	$7,945.18	$8,938.33	$9,405.11	$9,931.47
Reductant Costs		RC*H*RC	$27,243.60	$54,487.20	$75,192.34	$81,730.80	$108,974.40	$130,769.28	$136,218.00	$163,461.60	$190,705.20	$217,948.80	$245,192.40	$257,996.89	$272,436.00
SCR Catalyst Replacement Costs		H/SCL*SCC*1.11	$2,390.06	$4,780.12	$6,596.57	$7,170.18	$9,560.24	$11,472.29	$11,950.30	$14,340.37	$16,730.43	$19,120.49	$21,510.55	$22,633.88	$23,900.61
Operating Labor plus 15% for Supervisor		OW*OH*SY*1.15	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72	$13,574.72
Maintenance Labor plus Materials	D	MW*MH*SY*2	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70	$12,986.70
Total Direct Annual Costs	E	Sum(Row 12:Row17)	$57,188.22	$87,815.03	$111,091.41	$118,441.84	$149,068.65	$173,570.10	$179,695.46	$210,322.27	$240,949.07	$271,575.88	$302,202.69	$316,597.29	$332,829.50
Indirect Annual Costs															
Overhead	0.6D	OAQPS	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02	$7,792.02
Property Tax	0.02C	OAQPS using PA property tax of 2%	$7,268.68	$14,398.71	$19,817.53	$21,528.74	$28,658.77	$34,362.80	$37,476.96	$44,943.31	$52,409.66	$59,876.02	$67,342.37	$70,851.56	$74,808.72
Insurance	0.01C	OAQPS	$3,634.34	$7,199.36	$9,908.77	$10,764.37	$14,329.39	$17,181.40	$18,738.48	$22,471.65	$26,204.83	$29,938.01	$33,671.18	$35,425.78	$37,404.36
Administrative	0.02C	OAQPS	$7,268.68	$14,398.71	$19,817.53	$21,528.74	$28,658.77	$34,362.80	$37,476.96	$44,943.31	$52,409.66	$59,876.02	$67,342.37	$70,851.56	$74,808.72
Capital Recovery (5.5% @ 30 yrs)			$25,004.26	$49,531.56	$68,172.32	$74,058.87	$98,586.18	$118,208.02	$128,930.83	$154,617.09	$180,303.36	$205,989.63	$231,675.90	$243,748.44	$257,362.17
Total Indirect Annual Costs	F	Sum(Row 20:Row24)	$50,967.97	$93,320.36	$125,508.17	$135,672.74	$178,025.13	$211,907.04	$230,415.23	$274,767.39	$319,119.54	$363,471.69	$407,823.84	$428,669.35	$452,175.99
TOTAL ANNUALIZED COST	G	E+F	$108,156.20	$181,135.39	$236,599.58	$254,114.58	$327,093.78	$385,477.13	$410,110.69	$485,089.65	$560,068.61	$635,047.57	$710,026.53	$745,266.64	$785,005.49
Control Efficiency	CE		80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Potential to Emit (TPY)	PTE	ER*HP*H/(454 g/lb*2000 lb/ton)	38.59	77.18	106.51	115.77	154.36	185.23	192.95	231.54	270.13	308.72	347.31	365.45	385.90
Annual Estimated NOx Removal (TPY)	NR	PTE*CE	30.87	61.74	85.21	92.62	123.49	148.19	154.36	185.23	216.11	246.98	277.85	292.36	308.72
COST EFFECTIVENESS ($/Ton of NOx removed)		G/NR	$3,503.35	$2,933.63	$2,776.75	$2,743.72	$2,648.77	$2,601.29	$2,656.82	$2,618.80	$2,591.64	$2,571.27	$2,555	$2,549	$2,543
Assumptions:															
Power Consumption Rate (kW)	PC	OAQPS	1.53	3.06	4.22	4.59	6.12	7.34	7.65	9.18	10.71	12.24	13.77	14.49	15.30
Industrial Retail Power Price ($/kWh)	PP	EIA Data	$0.0741	$0.0741	$0.0741	$0.0741	$0.0741	$0.0741							
Reductant Consumption Rate (gal/h)	RC	OAQPS	1.244	2.488	3.433	3.732	4.976	5.971	6.220	7.464	8.708	9.952	11.196	11.781	12.440
Reductant Price ($/gal)	RP	Vendor's quote			$2.50										
SCR Catalyst Cost ($)	SCC	OAQPS	$4,916.00	$9,832.00	$13,568.16	$14,748.00	$19,664.00	$23,596.80	$24,580.00	$29,496.00	$34,412.00	$39,328.00	$44,244.00	$46,554.52	$49,160.00
SCR Catalyst Life (h)	SCL	Vendor's quote			20,000										
Operator Wages ($/h)	OW	MSC quote ($21.56/hr)			$21.56										
Operator Hours per Shift (h)	OH				0.50										
Shifts per Year	SY	3 shifts/day*365 days/year			1,095										
Maintenance Wages ($/h)	MW	MSC quote			$23.72										
Maintenance Hours per Shift	MH				0.25										
Interest Rate	IR				5.50%										
Equipment Life (y)	EL				30										
NOx Emission Rate (g/bhp-h)	NER	Uncontrolled NOx Emissions >500 bhp			8.0										

Appendix 30

Cost Analysis for NSCR for rich-burn engines

Based on E - C/R INC's Cost-Analysis done					
for EPA in June 2010					
HP	100	300	800	1500	3000
Hrs	8760	8760	8760	8760	8760
Total Capital Cost (TCC) in 2010	$15,139.00	$17,240.00	$33,103.00	$44,223.00	$89,644.00
Total Capital Cost (TCC) in 2020 (CPI 1.18)	$17,864.02	$20,343.20	$39,061.54	$52,183.14	$105,779.92
Total Annual Operating Cost (TAOC)	$5,466.00	$8,465.00	$10,723.00	$12,306.00	$18,773.00
Total Annual Operating Cost (TAOC) in 2020 (CPI 1.18)	$6,449.88	$9,988.70	$12,653.14	$14,521.08	$22,152.14
Uncontrolled NOx Gms/bhp-hr	16	16	16	16	16
Uncontrolled NMHC Gms/bhp-hr	1.00	1.00	1.00	1.00	1.00
Uncontrolled NOx tons per year	15.44	46.31	123.49	231.54	463.08
Uncontrolled NMHC tons per year	0.96	2.89	7.72	14.47	28.94
NOx removed TPY (80% Eff.)	12.35	37.05	98.79	185.23	370.47
NMHC removed TPY (50% Eff.)	0.48	1.45	3.86	7.24	14.47
Total NOx, NMHC removed	12.83	38.49	102.65	192.47	384.94
Cost-Effectiveness ($/Ton NOx removed) 2010 Dollars	$522.30	$269.62	$128.08	$78.39	$59.80
Cost-Effectiveness in 2020 Dollars with CPI 1.18	$616.32	$318.16	$151.13	$92.50	$70.56

Uncontrolled NOx Emissions used for this cost analysis - 16 gms/bhp-hr
Uncontrolled NMHC Emissions used for this cost analysis - 1.0 gms/bhp-hr

Typical NOx Control Efficiency 80%
HC Control Efficiency 50%

TCC = Direct Costs (DC) + Indirect Costs (IC)
DC = Purchased Equipment Cost (PEC) + Direct Installation Costs (DIC)
PEC includes Costs for Control Device and Auxiliary Equipment (EC), Instrumenttation (10% of EC), and Sales Tax and Fright (6% each of EC)
DIC includes Foundation and Supports (8% of PEC), Handling and Erection (14% pf PEC), and Electric (4% of PEC), Piping (2% of PEC), insulation (1% of PEC), and painting (1% of PEC)
IC Indirect Installation Costs (ICC) + Contingencies (C)
ICC includes Engineering (10% of PEC), Construction and Field expenses (5% of PEC), Contractor Fees (10% of PEC), Startup (2% of PEC), and Performance test (1% of PEC)
C is assumed to be 3% of PEC

TAC = DAC + IAC
DAC includes Utilities, Operating Labor, maintenance, Annual Compliance test, Catalytic Cleaning Catalyst replacement, Catalyst Disposal
IAC includes Overhead, Fuel Penalty, Property Tax, Insurance, Administrative Charges, and Capital Recovery (10% for 10 years)

Appendix 31

Cost Analysis for oxidation catalyst for IC engines						
	Cost	Costs	Costs	Costs	Costs	Costs
Uncontrolled NMHC gms/hp-hr	1	1	1	1	1	1
HP	2500	2000	1500	1000	750	500
Hrs/Yr	8760	8760	8760	8760	8760	8760
Capital Cost:						
TOTAL CAPITAL COST (TCC) (2009)	$35,069.00	$28,669.00	$22,269.00	$15,869.00	$12,669.00	$9,469.00
Direct Annual Costs						
On-Site Testing	$5,000.00	$5,000.00	$5,000.00	$5,000.00	$5,000.00	$5,000.00
Catalyst replacement (3 yrs Operating life)	$11,689.67	$9,556.33	$7,423.00	$5,289.67	$4,223.00	$3,156.33
Maintenance (5% of TCC)	$1,753.45	$1,433.45	$1,113.45	$793.45	$633.45	$473.45
Indirect Annual Costs						
Capital Recovery (5.5 % @ 20 yrs)	$2,935.28	$2,399.60	$1,863.92	$1,328.24	$1,060.40	$792.56
Overhead (60% of Maintenance - OAQPS)	$1,052.07	$860.07	$668.07	$476.07	$380.07	$284.07
PropertyTax+Ins.+Admn. (4% of TCC - OAQPS)	$1,402.76	$1,146.76	$890.76	$634.76	$506.76	$378.76
TOTAL ANNUALIZED COST	$23,833.22	$20,396.21	$16,959.20	$13,522.18	$11,803.68	$10,085.17
Total Uncontrolled NMHC emissions in Tons per Year	24.12	19.30	14.47	9.65	7.24	4.82
Total NMHC Removed in Tons per Year (60%)	14.47	11.58	8.68	5.79	4.34	2.89
Cost-Effectiveness ($/Ton NMHC removed) in 2009	$1,646.92	$1,761.77	$1,953.19	$2,336.02	$2,718.86	$3,484.53
COST-EFFECTIVENESS ($/Ton NMHC removed) in 2020 with CPI	$1,976.31	$2,114.13	$2,343.83	$2,803.23	$3,262.63	$4,181.43

Reference: June 29, 2010-Control Costs for Existing Stationary SI RICE
From: Bradley Nelson, EC/R, Inc.To: Melanie King, EPA OAQPS/SPPD/ESG
https://19january2017snapshot.epa.gov/sites/production/files/2014-02/documents/5_2011_ctrlcostmemo_exist_si.pdf

Appendix 32

Cost Analysis for SCR at Container and Flat glass furnaces					
Cost estimate	VITRO GLASS/Carlisle WORKS 6 flat at 26.75 lbs/ton	OWENS-BROCKWAY GLASS CONTAINER INC/CRENSHAW starting at 4 lbs/ton	OWENS BROCKWAY GLASS/CHERRY ST container starting at 4 lbs/ton	ARDAGH GLASS PORT ALLEGANY PLT container starting at 4 lbs/ton	Factors Used
Boiler Capacity MMBtu/hr	224	70.2	66.3	51.65	For Vitro - MMBtu/hr calculated from fuel flow in permit
Hrs/Yr	8760	8760	8760	8760	
NOx emissions (lb/MMBtu)	3.49	0.77	0.78	0.91	Vitro - 29.2 ton glass puled per hours in permit
TOTAL CAPITAL COST					
DIRECT CAPITAL COST					
Equipment Cost (EC) = (1)	$5,250,000.00	$2,975,852.00	$2,975,852.00	$2,975,852.00	Estimted based on similar size natural gas-fired boilers
Auxillaries = (2)					
Instrumentation & Controls = (3)	$525,000	$297,585	$297,585	$297,585	10% of EC
Sales Tax (6% of EC) = (4)	$315,000	$178,551	$178,551	$178,551	6% of EC
Freight (6% of EC) = (5)	$315,000	$178,551	$178,551	$178,551	6% of EC
Total Equipment Cost (TEC) = (6) = (1)+(2)+(3)+(4)+(5)	$6,405,000	$3,630,539	$3,630,539	$3,630,539	
INSTALLATION COSTS					
Direct Installation					
Foundation and Support = (7)	$512,400	$290,443	$290,443	$290,443	8% of TEC
Handling and Erection = (8)	$896,700	$508,276	$508,276	$508,276	14% of TEC
Electrical = (9)	$256,200	$145,222	$145,222	$145,222	4% of TEC
Piping (10)	$128,100	$72,611	$72,611	$72,611	2% of TEC
Insulation for duct work (11)	$64,050	$36,305	$36,305	$36,305	1% of TEC
Painting (12)	$64,050	$36,305	$36,305	$36,305	1% of TEC
Total Direct Installation Cost = (13) = (7)+(8)+(9)+(10)+(11)+(12)	$1,921,500	$1,089,162	$1,089,162	$1,089,162	
Indirect Installation					
Engineering and Supervision = (14)	$640,500	$363,054	$363,054	$363,054	10% of TEC
Construction, Field = (15)	$320,250	$181,527	$181,527	$181,527	5% of TEC
Construction or Contractor Fees = (16)	$640,500	$363,054	$363,054	$363,054	10% of TEC
Contingencies = (17)	$192,150	$108,916	$108,916	$108,916	3% of TEC
Startup and performance Tests = (18)	$192,150	$108,916	$108,916	$108,916	3% of TEC
Total Indirect Cost = (19) = (14)+(15)+(16)+(17)+(18)	$1,985,550	$1,125,467	$1,125,467	$1,125,467	
TOTAL CAPITAL COST (TCC) = 20 = (6) + (13) + (19)	$10,312,050	$5,845,168	$5,845,168	$5,845,168	
Direct Annual Costs					
Elecricity = (22)	$76,124	$76,124	$76,124	$76,124	$0.0676 kw/hr (prorated from 200 MMBtu quote)
Chemical Cost (Urea/Ammonia) = (23)	$206,606	$103,303	$103,303	$103,303	Estimated from EPA cost spreadsheet
Catalyst Replacement (costs/No. of years) = (24)	$47,528	$23,764	$23,764	$23,764	Estimated from EPA cost spreadsheet
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day = (28)	$32,850	$32,850	$32,850	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material = (29)	$32,850	$32,850	$32,850	$32,850	100% of maintenance labor
Indirect Annual Costs					
Administration (3% of maintenance+labor) = (25)	$3,154	$3,154	$3,154	$3,154	3% ofmaintenance +labor
Property Taxes (1% of TCC-OAQPS) = (26)	$103,121	$58,452	$58,452	$58,452	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS) = (27)	$103,121	$58,452	$58,452	$58,452	1% of TCC (OAQPS)
Annulized Capital Recovery Cost (30 yrs at 5.5%) = (21)	$709,469	$402,148	$402,148	$402,148	TCC*0.0688
Overhead (44% of Labor cost + 12% Material Cost) = (30)	$39,420.00	$39,420.00	$39,420.00	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST = (31) = Sum from (21) through (30)	$1,354,241	$830,515	$830,515	$830,515	
Uncontrolled NOx TPY = (32)	3,421.22	238.27	227.76	204.98	
NOx removed TPY (80% Eff.) = (33)	2,736.97	190.62	182.21	163.99	
COST EFFECTIVENESS ($/Ton of NOx removed) = (34) = (31)/(33)	$494.79	$4,356.97	$4,558.06	$5,064.51	
Calculated theoretical emissions after control (lbs NOx/ton glass)	5.35	0.80	0.80	0.80	% remainder after control*uncontrolled
RACT II emission limit (lbs NOx/ton glass) and §129.304	7.00	4.00	4.00	4.00	

Appendix 33

Cost Analysis for SCR for all other glass furnaces		
Cost estimate	PQ CORP/CHESTER other starting at 6 lbs/ton	Factors Used
Furnace Capacity MMBtu/hr	50	From Permit
Hrs/Yr	8760	
NOx emissions (lb/MMBtu)	1.20	Based on ~10 tons of glass pulled
TOTAL CAPITAL COST		
DIRECT CAPITAL COST		
Equipment Cost (EC) = (1)	$2,975,852.00	manipulated to agree with line 33 for 250 mmbtu
Auxillaries = (2)		
Instrumentation & Controls = (3)	$297,585	10% of EC
Sales Tax (6% of EC) = (4)	$178,551	6% of EC
Freight (6% of EC) = (5)	$178,551	6% of EC
Total Equipment Cost (TEC) = (6) = (1)+(2)+(3)+(4)+(5)	$3,630,539	
INSTALLATION COSTS		
Direct Installation		
Foundation and Support = (7)	$290,443	8% of TEC
Handling and Erection = (8)	$508,276	14% of TEC
Electrical = (9)	$145,222	4% of TEC
Piping (10)	$72,611	2% of TEC
Insulation for duct work (11)	$36,305	1% of TEC
Painting (12)	$36,305	1% of TEC
Total Direct Installation Cost = (13) = (7)+(8)+(9)+(10)+(11)+(12)	$1,089,162	
Indirect Installation		
Engineering and Supervision = (14)	$363,054	10% of TEC
Construction, Field = (15)	$181,527	5% of TEC
Construction or Contractor Fees = (16)	$363,054	10% of TEC
Contingencies = (17)	$108,916	3% of TEC
Startup and performance Tests = (18)	$108,916	3% of TEC
Total Indirect Cost = (19) = (14)+(15)+(16)+(17)+(18)	$1,125,467	
TOTAL CAPITAL COST (TCC) = 20 = (6) + (13) + (19)	$5,845,168	EPA cost spreadsheet for 250 MMBtu (Appendix 7)
Direct Annual Costs		
Elecricity = (22)	$76,124	$0.0676 kw/hr (prorated from 200 MMBtu quote)
Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day = (28)	$32,850	Maintenance Labor - $60/hr, 30 min/shift, 3 shifts/day
Maintenance Material = (29)	$32,850	100% of maintenance labor
Chemical Cost (Urea/Ammonia) = (23)	$103,303	from EPA cost spreadsheet for 250 MMBtu
Catalyst Replacement (costs/No. of years) = (24)	$35,964	from EPA cost spreadsheet for 250 MMBtu
Indirect Annual Costs		
Administration (3% of maintenance+labor) = (25)	$3,154	3% of maintenance + labor
Property Taxes (1% of TCC-OAQPS) = (26)	$58,452	1% of TCC (OAQPS)
Insurance (1% of TCC-OAQPS) = (27)	$58,452	1% of TCC (OAQPS)
Annulized Capital Recovery Cost (5.5% @ 30 yrs) = (21)	$402,148	TCC*0.0688
Overhead (44% of Labor cost + 12% Material Cost) = (30)	$39,420.00	60% of Maintenance Cost (OAQPS)
TOTAL ANNUALIZED COST = (31) = Sum from (21) through (30)	$842,715	
Uncontrolled NOx TPY = (32)	262.80	
NOx removed TPY (80% Eff.) = (33)	210.24	
COST-EFFECTIVENESS ($/Ton NOx removed) = (34) = (31)/(33)	$4,008.35	
Calculated theoretical emissions after control (lbs NOx/ton glass)	1.03	% remainder after control*uncontrolled
RACT II emission limit (lbs NOx/ton glass) and §129.304	6.00	